NORTH DAKOTA
DEPARTMENT *of* HEALTH

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October 2, 2018

Mr. Patrick Wauters
U.S. EPA, Region 8
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Coyote Station Title V Permit to Operate
EPA 45-day Review Period

Dear Mr. Wauters:

During the public comment period for the Coyote Station Title V Permit to Operate (T5-F84011), the Department received comments from one commenter. A copy of the comments was emailed to you on July 24, 2018. In the comments, the commenter contends that the Coyote Creek Mining Company (CCMC) mine and the Coyote Station should be considered the same stationary source for purposes of permitting under the Prevention of Significant Deterioration of Air Quality (PSD) and Title V rules. CCMC and Ottertail Power Company both responded to the comments and a copy of each response is enclosed.

In an April 11, 2013 stationary source determination (copy enclosed), the Department determined that the CCMC mine and the Coyote Station are to be considered separate sources. The Department issued an Air Pollution Control Permit to Construct for the CCMC mine on January 7, 2015. The CCMC mine began mining and processing coal in May 2016.

The applicable regulations consider a stationary source, or group of sources considered together, to be a major source if the stationary source (or group of sources) is located on one or more contiguous or adjacent properties and is under "common control" of the same person (or persons under common control). In addition, under PSD and Title V, the sources must be under the same industrial grouping (SIC code) to be considered part of the same stationary source.

In the above-referenced April 11, 2013 determination, the Department determined (based on the guidance available at the time) that the two facilities "do not appear to be under common control". When making this determination, the Department considered (as one of the factors) the extent of the support or dependency relationship between the two entities. In an April 30, 2018 letter (copy enclosed) from EPA to the Pennsylvania Department of Environmental Protection, EPA updated the interpretation of the term "common control". In the April 30, 2018 guidance, EPA states, "the agency believes clarity and consistency can be restored to source determinations if the assessment of "control" for title V and NSR permitting purposes focuses on the power or authority of one entity to dictate decisions of the other that could affect the applicability of, or compliance with, relevant air pollution regulatory requirements". In the April 30, 2018 guidance, EPA further clarifies that "a dependency relationship should not be presumed to result in common control".

When the support/dependency issue is removed from consideration (in accordance with the April 30, 2018 guidance), it is apparent to the Department that the CCMC mine and the Coyote Station are not under "common control" as the owners of the Coyote Station do not have authority to dictate decisions that could affect the applicability of, or compliance with, relevant air pollution regulatory requirements for the CCMC mine. For example, the CCMC mine is subject to a fugitive dust control plan and it is the sole responsibility of CCMC to demonstrate compliance with the plan.

The Department requests EPA's position as to whether the CCMC mine and the Coyote Station are to be considered under "common control" for air quality permitting purposes. Please provide EPA's position on this matter no later than November 17, 2018. Questions relating to the stationary source determination may be addressed to me at 701-328-5188 or cthorstenson@nd.gov.

Regardless of the ultimate "stationary source" determination, the Title V Permit to Operate for the Coyote Station is not expected to be significantly altered. This is due to the fact that the operation of the CCMC mine did not result in the physical alteration of any existing equipment at the Coyote Station; since no equipment was altered, a BACT analysis was not required for existing equipment at the Coyote Station. If it is ultimately determined that PSD review is required for the CCMC mine and associated equipment, then the additional requirements (BACT emission limits, etc.) will be established in a separate Permit to Construct for the CCMC mine and associated equipment with the requirements ultimately incorporated into a Title V permit.

A copy of the draft Title V permit and Statement of Basis for the Coyote Station is enclosed. Note that coal conveying/handling equipment has been added to the fugitive emission sources. Please review and provide comments regarding the draft permit by November 17, 2018. If you should have any questions regarding the Title V permit, please contact Kyla Schneider at (701)328-5188 or kkschneider@nd.gov.

Sincerely,

Craig D. Thorstenson
Environmental Engineer
Division of Air Quality

CDT:saj
Enc:
xc/enc: JJ England, Braaten Law Firm (via email)
Donn Steffen, Coyote Creek Mining Company (via email)
Mark Thoma, Ottertail Power Company (via email)

Coyote Creek Mining Company Response to Comments

COYOTE CREEK MINING COMPANY, L.L.C.

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A SUBSIDIARY OF THE NORTH AMERICAN COAL CORPORATION

August 29, 2018

Terry O'Clair, P.E.
Director, Division of Air Quality
North Dakota Department of Health
Gold Seal Center
918 E. Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Re: <u>Comments on Draft Permit TS-F84011 for Coyote Station</u>

Dear Mr. O'Clair:

Thank you for giving Coyote Creek Mining Company, LLC ("CCMC") an opportunity to respond to the comments by counsel for Casey and Julie Voigt on the draft Title V permit for Coyote Station. The comments are the latest attempt by the Voigts to impede CCMC's construction and operation of a lignite coal mine, large parts of which are located on property leased to CCMC by the Voigts. Their efforts to impede the mine have included appealing the mining permit to the state Supreme Court, objecting to a Mercer County road closure, and filing a federal Clean Air Act citizen suit. All of these attempts have been unsuccessful, with the most recent being the dismissal of Clean Air Act claims by the district court in a summary judgment decision for CCMC on July 3.

The comments by counsel for the Voigts do not specifically address emissions at Coyote Station but instead question the separate source determination that the North Dakota Department of Health ("NDDH") issued to CCMC on April 11, 2013. The request for the separate source determination by CCMC was accurate when it was made, and subsequent developments did not make it misleading. The determination by NDDH to treat CCMC's mine as a separate source from Coyote Station is consistent with the Clean Air Act and U.S. Environmental Protection Agency's ("EPA") interpretation of it. EPA issued additional guidance earlier this year that reinforces the determination made by NDDH in 2013.

The attached detailed response to the comments shows why the separate source determination remains valid and no permit action needs to be taken by NDDH in response to the comments. CCMC is ready to work with NDDH to address any further questions that you may have about the separate source determination.

CCMC appreciates the opportunity to provide this information to NDDH. Please call Donn Steffen (701-873-7823) or me (972-448-5400) if you have any questions.

Sincerely,

Miles B. Haberer

cc: Craig D. Thorstensen

Coyote Creek Mining Company's Response to
Separate Source Determination Comments
on Draft Permit TS-F84011 for Coyote Station

The North Dakota Department of Health ("NDDH") correctly determined[1] over five years ago that the lignite coal mine owned and operated by Coyote Creek Mining Company, L.L.C. ("CCMC") is a separate source from Coyote Station (the "NDDH Determination"). The comments made by counsel for Casey and Julie Voigt on the NDDH Determination in the context of the draft Title V permit for Coyote Station ("England's Comment Letter")[2] do not provide a factual or legal basis for changing the NDDH Determination. In fact, the basis for the NDDH Determination is even stronger today than it was in 2013.

The Coyote Creek Mine ("CCM") and Coyote Station do not comprise a single major source under applicable regulations. For two activities to be considered a single major stationary source, those activities must be: (1) located on contiguous or adjacent properties; (2) under "common control;" and (3) under the same industrial grouping ("SIC code"). The information about the location of CCMC's facilities relative to Coyote Station was accurate when it was provided in 2013, and CCMC provided information about the current configuration of its activities to NDDH in September 2014. CCMC and Coyote Station are not under common control; Coyote Station has no control over decisions that affect the applicability of, or compliance with, relevant air pollution regulatory requirements at CCM, and CCMC has no control over any decision-making at Coyote Station. And CCMC's coal mining operations and Coyote Station's electric generation activities belong to different industrial groupings. CCMC and Coyote Station are therefore separate sources for purposes of Prevention of Significant Deterioration ("PSD") and Title V permitting.

1. The Source Determination Request Accurately Stated What Was Known About the Configuration of the Facilities in 2013.

The request for a source determination by CCMC was accurate when it was submitted to NDDH in February 2013 (the "Source Determination Request").[3] The Source Determination Request stated that the "mining operations proper" would be located over three miles from Coyote Station. As actually constructed by CCMC, the mine face, the draglines and the

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[1] Letter from Terry L. O'Clair, Div. of Air Quality, North Dakota Dep't. of Health, to Donn Steffen, Coyote Creek Mining Co., LLC, regarding stationary source determination for the proposed Coyote Creek Mine and the existing Coyote Station, dated Apr. 11, 2013 and attached Memo to File from Craig D. Thorstenson, Div. of Air Quality, North Dakota Dep't. of Health, regarding Stationary Source Determination, dated April 11, 2013 (Exhibit 2 to England's Comment Letter).

[2] Letter from JJ England, Braaten Law Firm, to North Dakota Dep't. of Health regarding Comments of Casey & Julie Voigt on Draft Permit T5-F84011 for Coyote Station, dated July 21, 2018.

[3] Letter from Donn Steffen, Coyote Creek Mining Co., LLC, to Terry L. O'Clair, Div. of Air Quality, North Dakota Dep't. of Health, regarding Coyote Creek Mining Company L.L.C.'s Proposed Lignite Mine, Separate Stationary Source Determination Request, dated Feb. 13, 2013 (Exhibit 1 to England's Comment Letter).

equipment that removes the coal from the ground are in fact all over three miles away from Coyote Station.

The discussion in the Source Determination Request of options for delivery of coal to Coyote Station was accurate, and did not conceal any facts from NDDH as suggested by England's Comment Letter. According to that letter, the Source Determination Request did not mention "a private haul road directly connecting the mine pit area to this coal processing facility." England's Comment Letter conveniently omits the sentence from the Source Determination Request saying that "lignite will be hauled by truck, conveyor or similar haulage system around the Dakota Westmoreland property that currently separates the CCM from the Coyote Station."

Certain developments that occurred after the Source Determination Request was submitted are, of course, not reflected in the request, although the request attempted to identify the types of future developments that could be expected. The Source Determination Request said clearly that CCMC "was evaluating different options for delivering the lignite from the mining operations proper to Coyote Station." At that time, CCMC was considering both transport on public roadways and obtaining a private right-of-way for the haulage system around Dakota Westmoreland. From CCMC's perspective, the location of the coal processing facility was part and parcel of this evaluation, with consideration given to locations close to the mine face or in the vicinity of the processing facility's current location. No decision had been made about the processing facility's location when CCMC submitted the Source Determination Request to NDDH.

The location of the haul roads and processing facility ultimately constructed by CCMC could not have been identified in the Source Determination Request because the property was not even available in February 2013. Dakota Westmoreland, a competitor, held a lease on portions of the land, and CCMC could not consider using it for haul roads or a processing facility while the lease was in place. When Dakota Westmoreland dropped its lease in 2014, CCMC considered haulage systems that involved that land. The final decision on how to deliver crushed lignite to Coyote Station was made in approximately June 2014—more than one year after the Source Determination Request. The easement authorizing CCMC to use and retain exclusive control of all access to the property where the processing facility is located[4] was not finalized until September 2014.

As England's Comment Letter points out, the Source Determination Request also stated that "lignite will likely be conveyed by belt conveyor across the property/permit boundary between the CCM and the Coyote Station with transfer of ownership of the lignite occurring during the conveyance." This is exactly how the conveyor operates between CCMC's coal

[4] Easement Agreement by and among Otter Tail Power Company et al. and Coyote Creek Mining Company, L.L.C, for certain lands in Mercer County, North Dakota, dated Sept. 19, 2014 (granting "the right, privilege and authority to Grantee, its successors and assigns and their employees and representatives, of ingress, egress and regress in, upon, through and over the Subject Lands . . .") (Exhibit 5 to England's Comment Letter).

processing facility and Coyote Station. Counsel for the Voigts mistakenly claims that the conveyor "was actually constructed by Coyote Station itself." In truth, CCMC entered into a contract with Wanzek Construction, Inc. to build the conveyor, and CCMC paid for the construction. Once the construction was complete, Coyote Station purchased the portion of the conveyor located on Coyote Station's side of the boundary and the conveyor belt for an amount equal to the cost incurred by CCMC to purchase and install the equipment.

The main complaint by counsel for the Voigts seems to be that the Source Determination Request does not depict CCMC's facilities as they were actually constructed under plans developed later. To demonstrate this point, England's Comment Letter refers to CCMC's air permit application submitted to NDDH almost four years ago in September 2014. As discussed above, CCMC's plans had developed between the time of the Source Determination Request and the air permit application. CCMC again provided NDDH with all relevant and available information in the air permit application, which referred to the Source Determination Request and the NDDH Determination in several locations, including the very first page. In issuing a permit based on the 2014 application, NDDH did not indicate any concern as to whether the facilities depicted in the 2014 application were consistent with the facilities described in the 2013 Source Determination Request.

2. <u>CCMC and Coyote Station Are Not Under Common Control.</u>

The Source Determination Request demonstrated that CCMC and Coyote Station were not under common control based on U.S. Environmental Protection Agency ("EPA") rules, guidance and court decisions. NDDH reviewed this information and concluded that "CCM and Coyote Station do not appear to be under common control." England's Comment Letter does not offer contrary legal authority to that analyzed in either the Source Determination Request or the NDDH Determination.[5] Nor does England's Comment Letter address more recent EPA guidance that further strengthens NDDH's conclusion.

On April 30, 2018, EPA issued a letter and memorandum[6] ("2018 Common Control Guidance") analyzing whether two entities should be considered part of the same source for New Source Review permits under the Clean Air Act. The 2018 Common Control Guidance specifically rejects using support or dependency relationships between two entities to determine common control, and instead directs agencies to focus on the authority of one entity to dictate actions of the other that could affect the applicability of or compliance with air pollution

[5] Letter from William Spratlin, U.S. EPA, to Peter Hamlin, Iowa Dept. of Natural Resources, regarding new facilities that locate on the site of a present major source, dated Sept. 18, 1995, *available at*: https://www.epa.gov/sites/production/files/2015-08/documents/control.pdf; Letter from Richard Long, U.S. EPA, to Margie Perkins, Colorado Dept. of Public Health Env't. regarding Source Definition Issue for KN Power/Front Range Energy Associates, LLC/PSCo Generating Facility, dated Oct. 1, 1999 *available at*: https://www.epa.gov/sites/production/files/2015-07/documents/frontran.pdf.

[6] Letter from William Wehrum, U.S. EPA, to Patrick McDonnell, Pennsylvania Dep't. of Envtl. Prot. regarding aggregation of emissions from a biogas processing facility and a landfill, dated Apr. 30, 2018 and Attachment, *available at*: https://www.epa.gov/sites/production/files/2018-05/documents/meadowbrook_2018.pdf.

regulatory requirements.[7] EPA concluded that "control exists when one entity has the power or authority to restrict another entity's choices and effectively dictate a specific outcome, such that the controlled entity lacks autonomy to choose a different action," and made clear that the proper focus is on "control . . . over operations relevant to air pollution, and specifically control over operations that could affect the applicability of, or compliance with, permitting requirements."

Coyote Station does not "control" any of CCMC's operations—much less its compliance with regulatory requirements concerning air pollution. To the contrary, CCMC has independent and complete responsibility for all actions that "affect the applicability of and compliance with permitting requirements" at its facility.

England's Comment Letter does not address the 2018 Common Control Guidance. Instead, it mentions a few isolated terms of the long term lignite supply agreement between CCMC and Coyote Station that require CCMC to coordinate its capital expenditures and mining plans with Coyote Station. England's Comment Letter also notes that Coyote Station starts and stops the conveyor belt that runs from the coal processing facility into Coyote Station. Neither of these items affects the applicability of air pollution regulatory requirements to CCMC or its compliance with them.

CCMC explained in the Source Determination Request that the long term lignite supply agreement anticipated coordination on capital expenditures and mining plans because it is a "cost plus" agreement, but that many other functions, including environmental permitting and compliance and reclamation work, would be the exclusive responsibility of CCMC. The Source Determination Request noted that the lignite supply agreement does not give Coyote Station the ability to exercise authority over day-to-day mining operations, and expressly provides that the lignite supply agreement does not constitute a partnership between CCMC and Coyote Station. Indeed, the lignite supply agreement expressly states that CCMC "shall operate the Mine and perform all land, engineering, geological, operational, administrative and other work required to supply lignite."[8] And while the lignite supply agreement also gives Coyote Station's owners the right to inspect CCM, the agreement provides that "[s]uch inspection shall not be for any purpose or reserved right of controlling the methods and manner of the performance of the work by [CCMC] under this Agreement, but shall be to assure Buyer that [CCMC] is performing its obligations under this Agreement."

Only CCMC has the authority to install or operate pollution control equipment and conduct any attendant monitoring, testing, recordkeeping, and reporting obligations related to CCM. Only CCMC has the power to direct the construction or modification of equipment at CCM that will result in emissions of air pollution, as "CCMC owns all of its own equipment, including pollution control equipment" and there "is no overlap between the mine and the power

[7] *Id.* at 10.

[8] Lignite Sales Agreement between Coyote Creek Mining Company, L.L.C. and Otter Tail Power Company et al., dated Oct. 10, 2012.

plant"[9] pollution control responsibilities. And only CCMC has the power to direct the manner in which such emission units operate, because Coyote Station has no operational or management control of CCM, or any air pollution control equipment at CCM. This is reflected in the reality that CCMC, not Coyote Station, is legally responsible for any violations of law, including violations of environmental law, at CCM.[10]

The Source Determination Request addressed pollution control responsibilities in detail:

- *Do the facilities share equipment, other property, or pollution control equipment?* CCMC will own all of its own equipment, including pollution control equipment, and all other property. CCMC and the Coyote Station owners do not envision sharing any equipment.

- *What does the contract specify with regard to the pollution control responsibilities of the contractee?* The parties each have control over their own pollution control responsibilities. There is no overlap between the mine and the power plant. Although each has air and water permits, the permits are different in nature and are issued under separate categories for coal mining and power production.

- *Who accepts the responsibility for compliance with air quality control requirements?* What about for violations of the requirements? CCMC will be responsible for the operation of the proposed mine and is responsible for compliance with all air quality pollution control requirements. Legal liability for violations at the mine will fall exclusively on CCMC; the Coyote Station owners agreed to reimburse CCMC for financial penalties. CCMC has no responsibility for air quality control requirements at the plant, nor does it have any legal liability for any violations. The Coyote Station owners are responsible for air quality control requirements, and liability for such violations is between the owners.

- *Can the managing entity of one facility make decisions that affect pollution control at the other facility?* CCMC and Coyote Station would be operated by separate companies that do not make decisions regarding pollution control at each other's facilities.

Any lingering doubt about the impact of these arrangements on NDDH's conclusion was removed by the 2018 Common Control Guidance. It addressed a situation where a landfill planned to supply landfill gas to another entity that would convert landfill gas to transportation fuel. The fuel producer could operate a shut-off valve to stop the flow of landfill gas, but the landfill operator would still satisfy environmental requirements when the fuel refiner was not accepting landfill gas. Similarly, the fact that Coyote Station can shut off the conveyor and stop

[9] Source Determination Request at 6.

[10] *Id.*

the flow of coal does not affect CCMC's responsibility or ability to achieve environmental compliance for its own operations.

NDDH correctly decided that CCMC and Coyote Station did not appear to be under common control based on the rules and guidance available in 2013, including an EPA determination that a lignite mine and a nearby mine-mouth power plant are separate sources.[11] In applying the now-superseded support or dependency test, NDDH considered that Coyote Station had a long operating history; that CCMC is free to sell coal to other parties; that Coyote Station's prior coal supplier did not go out of business after the non-renewal of the supply contract; and that CCM does not produce a specific product that can only be used by Coyote Station. NDDH concluded "that there is a reasonable possibility that each facility could continue to operate if the other facility were to shut down. Therefore, a support or dependency relationship does not appear to exist to such an extent that the two facilities should be considered to be under common control."[12] Counsel for the Voigts has not provided any basis to disturb NDDH's determination. Thus, even if NDDH does not follow EPA's new guidance, there is no basis for finding common control. CCM and Coyote Station are independent enterprises in an arm's-length relationship.

3. <u>CCMC and Coyote Station Do Not Belong to the Same Industrial Grouping.</u>

Counsel for the Voigts does not dispute that a coal mine and an electric power plant belong to different industrial groupings. This is relevant because the PSD rules define a source to include all activities "which belong to the same industrial activity" that are under common control on contiguous or adjacent properties.[13] To determine whether activities belong to the same industrial grouping, EPA uses the Standard Industrial Classification ("SIC") major group for the activities. The NDDH Determination found that CCMC's "coal mine is in SIC major group 12 while Coyote Station is under SIC major group 49."

This result is consistent with the understanding of Congress when it adopted the PSD definition of "major source" for Title V permits in 1990. The House Report supporting the legislation favorably notes EPA's use of SIC major groups in making source determinations because it "avoids the possibility that *dissimilar sources, like a power plant and an adjacent coal mine*, will be considered as the same 'source' because of common ownership."[14] England's Comment Letter attempts to overcome these authorities by referring to the "support activities" concept that is mentioned in the NDDH Determination.

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[11] U.S. EPA, "Draft NSR Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting," Oct. 1990 at A. 29, *available at*: https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf.

[12] Source Determination at 2.

[13] 40 C.F.R. §52.21(b)(6).

[14] H.R. Rep. No. 101-490(I), at 236-37 (1990) (emphasis added).

In EPA's proposal to add 40 C.F.R. Part 70 for State Operating Permit Programs, EPA specifically acknowledged Congress' understanding that the use of SIC code criteria was meant to *avoid* aggregating a power plant and an adjacent coal mine into a single source.[15] While EPA went on to outline a support facility test that might be relevant in some situations—like a foundry that served a co-located automobile plant—EPA never suggested that that coal mines and adjacent power plants should be aggregated.[16]

The NDDH Determination described the "support activities" concept by referring to a 1996 EPA guidance document[17] about the industrial grouping criteria for identifying sources at military bases. Before the guidance, all activities at military bases were assigned to the same SIC major group and would be considered a single source if under common control and contiguous or adjacent. After the guidance, the activities could be treated as separate sources in determining whether New Source Review and Title V permit requirements applied. EPA used the support facilities concept to prevent aggregation of similar operations at military bases that supported different activities. The guidance gives the example of boilers at a school on a military base that would be grouped with the school and not with other boilers on the base.

Whatever the merits of the support activities concept may be in other situations, it would be contrary to the clearly expressed intent of Congress[18] to apply the concept to a power plant and an adjacent coal mine. EPA has consistently applied the industrial grouping test to find that coal mines and power plants are different sources *even when they are close together and have common ownership*, as summarized in the Source Determination Request.[19] Expanding the concept of support facilities to find that coal mining by CCMC is a support facility for electric power generation by Coyote Station would be inconsistent with previous policy and practice.

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[15] 56 Fed. Reg. 21,712, 21,724 (May 10, 1991).

[16] Moreover, EPA proposed but then rejected the inclusion of a 50% output test for the identification of any support facilities in the Clean Air Act regulations. 59 Fed. Reg. 44,515 at 44,562-27 (Aug. 29, 1994) (proposing addition of support facility test to "major source" definition at 40 C.F.R. § 70.2); 60 Fed. Reg. 20,804 at 20,829 (Apr. 27, 1995) (proposing addition of support facility test to "major source" definition at 40 C.F.R. § 71.2). The plain language of 40 C.F.R. § 70.2 and 40 C.F.R. § 71.2 does not include a support facility test. See *Color Commc'ns, Inc. v. Illinois Pollution Control Bd.*, 680 N.E. 2d 516, 533 (Ill. Ct. App. 1997), *petition for leave to appeal denied*, 686 N.E.2d 1159 (Ill. 1997) ("A plain reading . . . is that if several stationary sources do not have the same two-digit SIC code, they do not belong to the same industrial grouping.").

[17] Memorandum from John Seitz, Office of Air Quality Planning and Standards, U.S. EPA, regarding Major Source Determinations for Military Installations under the Air Toxics, New Source Review, and Title V Operating Permit Programs of the Clean Air Act, dated Aug. 2, 1996, *available at*: https://www.epa.gov/sites/production/files/2015-08/documents/dodguid.pdf.

[18] H.R. Rep. No. 101-490(I), at 236-37 (1990).

[19] U.S. EPA, "Draft NSR Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting," Oct. 1990 at A. 29, *available at*: https://www.epa.gov/sites/production/files/2015-07/documents/1990wman.pdf; Letter from to Laura Burrell, Mississippi Dep't of Envtl. Quality regarding Secondary Emissions for PSD Air Quality Assessments, dated Jan. 20, 1998) (treating power plant and an adjacent lignite mine as separate sources).

It would also be inconsistent with the policy choice made by EPA to treat coal mines differently from power plants. Unlike electric generating units, coal mines are not listed as a "major emitting facility" in the PSD rules and are not subject to standards of performance for new stationary sources.[20] The only coal-mining related sources specifically identified as a "major emitting facility" are coal cleaning plants, including thermal dryers.[21] And EPA has a longstanding position that fugitive emissions from a coal mine should not be considered in determining threshold applicability for a source consisting of the mine and some other co-located activity;[22] it considers the Surface Mining Control and Reclamation Act sufficient to address fugitive emissions from mine haul roads, including those that go to coal preparation and processing plants.[23] These regulatory differences underscore the appropriate treatment of coal mines and power plants as separate sources.

Even if a support facility analysis were employed, the actual nature of the relationship between CCMC and Coyote Station would weigh in favor of finding that the mine is not a support facility to Coyote Station. First, EPA defines "support facilities" as "those which convey, store, or otherwise assist in the production of a principal product."[24] EPA's original illustration of a support facility is instructive: a boiler "used to generate *process* steam" for a pulp mill.[25] Process steam is steam used for heat and moisture rather than for power.[26] In a pulp mill, process steam is used to evaporate moisture from pulp and to heat rotating dryer drums in making paper. Unlike CCMC's coal, the process steam from the boiler is not a separately manufactured product purchased and consumed by the paper manufacturer; it is a part of the paper manufacturing process itself.

CCMC does not "convey" or "store" Coyote Station's "principal product"—electricity. Nor does CCMC "otherwise assist" in the production of electricity. Rather, CCMC separately produces its own product—coal—and sells that product under contract to an independently owned power generator. The examples of facilities that EPA has deemed to be support facilities are limited to situations where the supporting facility provides direct assistance in the production

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[20] 40 C.F.R § 52.21(b)(1)(i); 42 U.S.C § 7479(1).

[21] *Id.*

[22] Memorandum from Edward E. Reich, Stationary Source Compliance Division, U.S. EPA, to John M. Daniel, Virginia Air Pollution Control Board, regarding impact of fugitive dust on PSD applicability decision, dated May 31, 1983; Letter from Edwin Erickson, U.S. EPA, to Henry Nickel, Hunton & Williams, regarding Consolidate Coal Company appeal, dated Mar. 24, 1995.

[23] 74 Fed. Reg. 51,950, 51,954 (Oct. 8, 2009).

[24] 45 Fed. Reg. 52,676, 52,695 (Aug. 7, 1980).

[25] *Id.*

[26] Process Steam, *Merriam-Webster*, https://www.merriam-webster.com/dictionary/process%20steam?utm_campaign=sd&utm_medium=serp&utm_source=jsonld (last visited Aug. 17, 2018).

of the principal product. A vendor of raw materials like CCMC cannot appropriately be said to "assist" in the production of its customers' products.

Moreover, reliance on a 50% of output approach to presume[27] that one facility merely "supports" another does not account for the potentially shifting nature of the relationship between an independently owned vendor and customer over time. CCMC has the capability and authority to sell lignite to other parties, and in certain situations Coyote Station can obtain fuel from other sources. The fact that CCMC has not supplied coal to other sources besides Coyote Station during the first three years of operation does not mean it cannot or will not supply other customers over the remaining life of the mine.

The history of the nearby Dakota Westmoreland Beulah mine described in the Source Determination Request is illuminating. The Beulah mine supplied coal to Coyote Station for 34 years. When Coyote Station switched its coal supplier to CCMC in 2015, the Beulah mine did not shut down, as would be expected if it were a support facility. Instead, it continued to operate and supply coal to third parties. Although the area where coal is removed from the ground at the Beulah mine is physically closer to Coyote Station than the area where coal is removed from the ground at the CCM, CCMC does not believe that there was ever any suggestion that the Beulah mine was a "support facility" for Coyote Station when the Beulah mine supplied coal to Coyote Station.

Even if NDDH elects to use the 50% output presumption, the facts in this case rebut the presumption. Those facts, as identified in the relevant guidance,[28] include that: (1) CCM does not receive materials or services directly from Coyote Station; (2) Coyote Station has no authority to control day-to-day operations at CCMC (controlling when Coyote Station receives coal in its storage barn, and coordinating capital expenditures and mining plans, does not alter this fact); (3) neither the mining activities at CCM nor the coal processing facility have to be at their current locations to provide coal to Coyote Station, as is shown by the fact that another mine supplied Coyote Station for 34 years; and (4) other coal mines exist in the vicinity of CCMC that serve other customers besides Coyote Station (showing that CCM could exist at its current location without Coyote Station).

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[27] The 1996 EPA guidance document explains that the 50% output test is only a presumption and additional consideration as to how the facilities interact, including review of contractual agreements and other relevant information, is merited. *Id.* at 10. As discussed in relation to common control, Coyote Station does not exert control over CCMC's operations, nor do the contractual arrangements between the facilities indicate anything but a typical arm's-length transaction between a purchaser and supplier.

[28] Letter from Robert Miller, U.S. EPA, to William Baumann, Wisconsin Dep't. of Natural Resources, regarding Oscar Mayer Foods facility, dated Aug. 25, 1999, *available at*: https://www.epa.gov/sites/production/files/2015-07/documents/oscar.pdf.

4. The Relief Requested in the Comments Mistakenly Assumes that CCMC Is a Major Source.

The relief requested in England's Comment Letter is based on the mistaken assumption that the calculated emissions from the relevant CCMC facilities would exceed the threshold for a major modification. CCMC's experts in the recent Clean Air Act litigation concluded that emissions from activities at the coal processing facility (including the crushing equipment designed with a passive enclosure containment system and the three-quarter enclosed conveyor belt) would be negligible—less than one ton per year—and that emissions from activities at the coal stockpile (including coal unloading, bulldozer operations and wind erosion) would potentially amount to only about 40-60 tons per year, without accounting for the federally enforceable dust control measures that CCMC currently implements under the terms of its permit and under state law.

Recent permits indicate that effective dust control measures should have a 50%-90% control efficiency.[29] CCMC has such measures in place. For example, CCMC used 31 million gallons of water for dust suppressant purposes in 2016, 33.7 million gallons in 2017 and 21.4 million gallons through the end of July 2018. CCMC also used calcium chloride as a chemical dust suppressant on its haul roads. CCMC believes that a reasonable calculation of its potential to emit in stockpiling, transporting, processing and conveying lignite coal could be below the threshold for a major modification, especially when the required dust suppression measures are considered.

The suggestion in England's Comment Letter as to what controls would be BACT at CCMC is also mistaken. There are BACT determinations for similar facilities that require nothing more than the dust suppression techniques currently employed by CCMC. For example, in a fairly recent permit for a sawmill with regular use of both paved and unpaved roads, the state agency acknowledged that "there is no technically feasible add-on control technology for PM emissions from haul roads," and found daily watering to be a sufficient BACT control.[30] Similarly, customary BACT control measures for open coal piles include wet suppression with pile compaction and implementation of wet suppression of dust generating sources by water

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[29] Permit to Construct Operate and Maintain for Union County Lumber Company – El Dorado Sawmill, Permit No. 2348-AOP-R0, issued Aug. 3, 2015 by the Arkansas Dep't. of Envtl. Quality, *available at*: https://www.adeq.state.ar.us/DOWNLOADS/WEBDATABASES/PERMITSONLINE/AIR/2348-AOP-R0.PDF. "[D]aily watering of roads has been shown to decrease emissions about 90%."

[30] Permit to Construct Operate and Maintain for Union County Lumber Company – El Dorado Sawmill, Permit No. 2348-AOP-R0, issued Aug. 3, 2015 by the Arkansas Dep't. of Envtl. Quality, *available at*: https://www.adeq.state.ar.us/DOWNLOADS/WEBDATABASES/PERMITSONLINE/AIR/2348-AOP-R0.PDF. (No BACT determinations were located that require paving of roads as a control method. Permit required watering for dust suppression.) *See also* Air Quality Construction Permit for Donlin Gold Project, Permit No. AQ0934CPT01, issued June 30, 2017 by Alaska Dep't. of Envtl. Conservation, *available at*: http://dec.alaska.gov/Applications/Air/airtoolsweb/Home/ViewAttachment/16763360/d1h2U6BIY-j857LFU-WYmw2 (determining that BACT for particulate matter ("PM") from loading and unloading activities as well as erosion requires quarterly inspections and application of water "[i]f excessive dust is present").

sprays at each storage pile site.[31] These are the controls that CCMC already implements at the coal pile. Moreover, with a total of only 100 *pounds* per year of estimated potential PM from the three-quarter enclosed conveyor, it is clear that CCMC already employs an extremely effective method of emission control at the conveyors, and nothing more would be necessary to address conveyor emissions.

5. Conclusion

In the Source Determination Request, CCMC presented accurate information that supported and continues to support the finding that that CCMC's lignite coal mine is a separate source from Coyote Station. NDDH's determination that these "facilities are to be considered separate 'sources' for the purposes of [PSD, Section 112 air toxics and Title V]" remains valid as the facilities are not under common control or in the same industrial grouping.

[31] See generally RACT/BACT/LAER Clearinghouse, https://cfpub.epa.gov/rblc/index.cfm?action=Search.BasicSearch&lang=en. *See also* Notice of Decision for Indiana Gasification LLC, PSD New Source Construction/Part 70 Operating Permit No.: T 147-30464-00050, issued June 27, 2012 by Indiana Dep't. of Envtl. Mgmt., *available at*: http://permits.air.idem.in.gov/30464F.PDF (determining that wet suppression with pile compaction at coal piles and wet suppression with pile compaction for dozer activities within coal conveying and storage area are BACT for PM, PM10 and PM2.5).

Ottertail Power Company Response to Comments

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August 29, 2018

OTTER TAIL POWER COMPANY

Mr. Terry O'Clair, P.E.
Director, Division of Air Quality
North Dakota Department of Health
Gold Seal Center, 918 E. Divide Avenue
Bismarck, ND 58501-1947

Re: Response to Comments of Casey and Julie Voigt on Draft Permit T5-F84011

Dear Mr. O'Clair,

Otter Tail Power Company ("Otter Tail") appreciates the opportunity to respond to the July 21, 2018 comments filed by counsel for Casey and Julie Voigt (the "Voigt Letter") on the North Dakota Department of Health's ("NDDH" or "Department") draft Title V renewal permit number T5-F84011 for Coyote Station. The Voigts argue that Coyote Station and the Coyote Creek Mine ("Mine"), a lignite mine owned by Coyote Creek Mining Company, L.L.C. ("CCMC," a wholly-owned subsidiary of The North American Coal Corporation), should be considered a single stationary source for Clean Air Act ("CAA") permitting purposes, and that the Department's draft Title V renewal permit for Coyote Station is incomplete because it does not contain applicable requirements for the Mine. They also claim that construction of the Mine at that purported single source should have triggered Prevention of Significant Deterioration ("PSD") preconstruction review and imposition of best available control technology ("BACT") emission limits.

The Voigts are incorrect, and their argument relies on a misreading of the relevant regulatory provisions and misstatements about the procedural and factual background. Tellingly, Otter Tail is unaware of any previous NDDH determination of a mine-mouth power plant and its associated coal mine to be a single stationary source.

With regard to these particular facilities, NDDH has twice had an opportunity to assess this issue, in a 2013 "source determination" letter and in the 2016 air permit for the Mine, and both times correctly concluded that the Mine is a separate source from Coyote Station. Assuming that the two sources are adjacent, as the Voigts assert, they are not under common control and are not part of the same major industrial grouping. Furthermore, assuming for the sake of argument only that Coyote Station and the Mine were a single source, construction of the Mine would not have subjected any emission units (other than the new conveyor) at Coyote Station to BACT.

I. Background

Otter Tail Power Company co-owns and operates the Coyote Station power plant, a lignite coal-fired power plant in Mercer County, North Dakota. Until 2016, Coyote Station combusted lignite from the neighboring Dakota Westmoreland Corporation Beulah Mine. Currently, Coyote Station combusts lignite from the more recently constructed Coyote Creek Mine, pursuant to an October 10, 2012 Lignite Sales Agreement ("LSA") between CCMC and the owners of Coyote Station (collectively referred to herein as "Otter Tail"). CCMC mines lignite from its primary mining operations 3-4 miles from Coyote Station and transports it by truck along haul roads to a processing facility constructed by CCMC near the fenceline of Coyote Station.[1]

CCMC first stores the mined lignite in a coal pile outside of the processing facility, where the lignite is processed (i.e., primarily crushed and sorted) and then delivered to Coyote Station across the fenceline via a conveyor belt. Three-fourths of the conveyor belt is enclosed to control and minimize fugitive emissions and these measures have consistently resulted in zero percent opacity upon testing since construction.[2] The conveyor structure is owned by Coyote Station on its side of the fence, and by CCMC on CCMC's side of the fence. The belt itself is owned and maintained by Coyote Station. Title for the lignite transfers to Coyote Station at the fenceline. Coyote Station operates pursuant to permit number T5-F84011, a major source operating permit issued by NDDH pursuant to Title V of the CAA.

In February 2013, after the LSA had been executed but before construction of the Mine had begun, CCMC requested an express determination that the Mine is a separate stationary source from Coyote Station for CAA purposes. Letter from Donn Steffen to Terry O'Clair, "Coyote Creek Mining Company, L.L.C.'s Proposed Lignite Mine, Separate Stationary Source Determination Request" (Feb. 13, 2013) ("Source Determination Request"). At the time of that request, CCMC had not yet finalized site development and layout plans for the Mine, including the location of the Mine's lignite processing and transfer facilities. On April 11, 2013, NDDH determined that the Mine is a separate stationary source from Coyote Station. Letter from Terry O'Clair to Donn Steffen (Apr. 11, 2013) ("2013 Determination"). NDDH observed that the Mine and Coyote Station "do not appear to be under common control and it is unclear if the two sources should be considered under the same SIC code," but because "the two sources are not located on contiguous or adjacent properties," they cannot constitute a single stationary source. *Id.* at 3. On September 9, 2014, CCMC submitted an application to NDDH for a permit to construct the Mine. This application included detailed final plans for the Mine, including the location of haul roads, the coal pile, the coal processing facility, and the conveyor belt for transfer of lignite to Coyote Station. The Department granted that permit.

Coyote Station is currently seeking renewal of its Title V operating permit. In comments on the facility's draft Title V permit, Casey and Julie Voigt have argued that the NDDH's determination that Coyote Station and the Mine are separate stationary sources is incorrect, asserting that construction of the coal processing facility on property abutting the Coyote Station site

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[1] The Voigts claim incorrectly that "the conveyor belt that enters into the coal processing facility was actually constructed by Coyote Station itself." Voigt Letter at 3-4 & n.15. The Voigts have misread the document they cite. In fact, CCMC entered into a contract to build the conveyor and paid for its construction. After the conveyor was built, Coyote Station purchased the portion of the conveyor located on its site of the fenceline and the conveyor belt at cost.

[2] Annual opacity performance tests have been submitted to the Department under cover letters dated September 2, 2016, August 30, 2017, and August 17, 2018.

undermines the conclusion that the two sources are not adjacent. Accordingly, the Voigts argue that the Mine should be included in Coyote Station's Title V permit, and that construction of the Mine was a major modification of a major stationary source that should have triggered preconstruction review under the PSD permitting program.

II. NDDH Correctly Determined Coyote Station and the Mine Are Separate Sources.

For the purposes of the CAA's Title V and PSD permitting programs, stationary sources must be grouped together and treated as a single source if they: (1) are located on one or more contiguous or adjacent properties; (2) are under common control of the same entity (or entities under common control); and (3) belong to a single major industrial grouping, indicated by a shared first-two-digit code in the Standard Industrial Classification Manual ("SIC code"). 40 C.F.R. §§ 52.21(b)(6) (defining "building, structure, facility, or installation" for PSD program) & 70.2 (defining "major source" for Title V program).[3] If any single criterion is not met, the facilities are not a single source. Permitting authorities conduct this analysis on a case-by-case basis and should be guided by the "common sense notion of [a] 'plant.'" 45 Fed. Reg. 52,676, 52,694-95 (Aug. 7, 1980) (citing *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979)).

A. Adjacency

In its 2013 Determination, NDDH primarily relied on this criterion to conclude the Mine and Coyote Station are separate sources. *See* 2013 Determination at 3 ("Since the two sources are not located on contiguous or adjacent properties, the sources are considered separate...."). The Voigt Letter argues this conclusion was based on "materially false and inaccurate" submissions from CCMC. Voigt Letter at 3. Specifically, the Voigts argue CCMC did not sufficiently disclose the existence or location of Mine facilities that would be used to process and transfer lignite to Coyote Station.

But the Voigts' own comments undermine their claim. Although the precise layout and location of the Mine's lignite processing and transfer facilities had not been finalized in early 2013, as the Voigt Letter itself notes, CCMC's 2013 letter fully disclosed that:

> [t]he lignite will be hauled by truck, conveyor, or similar haulage system around the Dakota Westmoreland property that currently separates the [Mine] from the Coyote Station. The lignite will likely be conveyed by belt conveyor across the property/permit boundary between the [Mine] and the Coyote Station with transfer of ownership of the lignite occurring during the conveyance.

Source Determination Request at 9-10 (quoted in part in Voigt Letter at 3). Further, CCMC's September 2014 operating permit application for the Mine fully disclosed the source's final layout plan, including the locations of "a private haulroad directly connecting the mine pit area to

[3] Because North Dakota operates its own EPA-approved Title V and PSD programs, the corresponding provisions that govern Coyote Station and the Mine are contained in the North Dakota Administrative Code at NDAC 33-15-14-06(1)(q) and NDAC 33-15-15-01.2, respectively. The remainder of these comments will cite to the EPA regulations, which are similar—if not identical—to the State regulations.

[the] coal processing facility," "an eight acre open coal storage pile, a primary coal crusher, a secondary coal crusher, and a conveyor belt to directly convey crushed coal to Coyote Station." Voigt Letter at 3 (citing CCMC Application for Air Quality Permit to Construct).

In short, CCMC accurately provided available information about the Mine's layout to NDDH in 2013 when NDDH made its single source determination, and again in 2014 when CCMC applied for the construction permit that NDDH issued authorizing construction of the Mine (including its coal processing facility) as a separate source from Coyote Station.

B. Common Control

Coyote Station and the Mine do not share a common owner. Nevertheless, the Voigts argue this criterion is met because "Coyote Station exerts complete control over Coyote Creek Mine." Voigt Letter at 4. This argument fails for several reasons.

At the most basic level, the Voigts' analysis is outdated because it fails to address EPA's most recent interpretation of the "common control" criterion. While the Voigt Letter is limited to EPA's previous "multi-factor" analysis, which often turned on questions of economic or operational dependency between the sources, EPA's current interpretation of the "common control" criterion focuses on whether one entity has the power to dictate the other's decisions *that affect the applicability of or compliance with relevant air pollution regulatory requirements*. *See* Letter from William L. Wehrum to Patrick McDonnell (Apr. 30, 2018) ("Meadowbrook Guidance").[4] Otter Tail does not exercise any authority over the Mine's compliance with its environmental obligations. But even under EPA's old interpretation, nothing in the relationship between Coyote Station and the Mine rises to the level of influence or "but for" dependency that would constitute common control under that approach. Rather, whatever involvement Otter Tail has in reviewing and approving the Mine's mining plans and capital expenditures is a natural reflection of an arms-length cost-plus contract for providing lignite to the Station.

<u>Current EPA Policy</u>[5]

In its 2018 Meadowbrook Guidance, EPA updated its interpretation of the term "common control" in order to "better reflect a 'common sense notion of a plant,' and to minimize the potential for entities to be held responsible for decisions of other entities over which they have no power or authority." Meadowbrook Guidance at 6. Under this interpretation, the assessment of "control" should focus on "the power or authority of one entity to dictate decisions of the

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[4] Available at https://www.epa.gov/sites/production/files/2018-05/documents/meadowbrook_2018.pdf.

[5] Otter Tail recognizes that NDDH's interpretation of its PSD regulations, including what it means for two sources to be under common control, governs in North Dakota. NDDH has traditionally adopted EPA's interpretation of this term, however, and we believe NDDH would likely adopt the Meadowbrook Guidance because that guidance is well-reasoned, establishes clear and objective criteria, and yields conclusions that better comport with the "common sense notion of a plant."

other that could affect the applicability of, or compliance with, relevant air pollution regulatory requirements." *Id.*

For the purposes of this analysis, "control" must be distinguished from the more general ability of one entity to *influence* another. "[T]he fact that an entity is influenced, affected, or somewhat constrained by contractual relationships that it negotiated at arm's length, or by external market forces, does not necessarily mean that one entity is actually controlled or governed by these influences in making a given decision." *Id.* at 7. To reflect "control," the entity must have authority to "expressly or effectively force another entity to take a specific course of action, which the other entity cannot avoid through its own independent decision-making." *Id.* "Control" is also not synonymous with dependency, which EPA now states is relevant only for analyzing whether one entity is a "support facility" of another for the purposes of the "major industrial grouping" criterion. *Id.* at 10-11; *see infra* Section II.C (discussing support facility analysis).

Likewise, the "control" must extend to "whether a permitting requirement applies or does not apply to the other entity, or whether . . . the other entity complies or does not comply with an existing permitting requirement." Meadowbrook Guidance at 8. Where "each entity has autonomy with respect to its own permitting obligations ... [i]t is more logical for such entities to be treated as separate sources." *Id.* Otherwise, a source's responsible official could be required to certify compliance with requirements when knowledge of that compliance is limited to the other entity, or a source could face liability for the actions of another entity that were outside the source's control. *Id.* at 9. EPA believes the most relevant considerations should include "the power to direct the construction or modification of equipment that will result in emissions of air pollution; the manner in which such emission units operate; the installation or operation of pollution control equipment; and monitoring, testing, recordkeeping, and reporting operations." *Id.* at 9-10.

Here, Coyote Station does not control the Mine's environmental obligations or compliance. The LSA provides for some degree of coordination between Otter Tail and CCMC with respect to the Life-of-Mine Plan and Annual Mining Plans. *See* LSA ¶¶ 5.2.1-5.2.3.[6] But these review and approval provisions simply reflect Otter Tail's need for some oversight of the Mine's costs in light of the LSA's "cost plus" compensation structure. *See id.* ¶ 7.2 (explaining Coyote Station will compensate CCMC for the costs of production plus an agreed profit and capital charge). The provisions of these plans do not include any decisions with respect to permitting or environmental compliance: they are focused on capital expenditures and operating costs and expenses. At most, the required Annual Mining Plan provisions on "planned mine progression, location of infrastructure, and capital project locations" might be construed as decisions on "the construction or modification of equipment that will result in emissions," *see* Meadowbrook Guidance at 9, but the LSA does not provide for any review of how the Mine will meet its environmental obligations for those projects. *See* LSA ¶ 5.2.2(b)(i). Moreover, Otter Tail does not have authority over the manner in which Mine emission units operate; the operation of pollution controls (which, for mining activities, largely consists of dust suppression practices); or

[6] Excerpts of the LSA cited herein are attached as Exhibit 1. Portions of some LSA provisions have been redacted to preserve confidential information.

monitoring, testing, recordkeeping, or reporting. Therefore, the Voigt Letter is incorrect when it states that Coyote Station "must approve all activities at CCMC." Voigt Letter at 5.

In fact, the LSA explicitly denies Otter Tail any authority to control CCMC's day-to-day operation of the Mine. While Otter Tail retains the right to access the Mine for periodic inspections, including inspection of "environmental and permitting materials," the LSA specifies that "[s]uch inspection shall not be for any purpose or reserved right of controlling the methods and manner of the performance of the work by [CCMC]...." LSA ¶ 12.3(a).

In short, CCMC is solely responsible for obtaining the permits for the Mine and for implementation of and compliance with pollution control requirements. Otter Tail exercises no control over these activities—quite the opposite, the LSA explicitly denies Otter Tail such control. Therefore, the Coyote Station and the Mine are not under common control and do not constitute a single major source under the CAA.

Previous EPA Policy

While EPA's Meadowbrook Guidance reflects EPA's current authoritative interpretation of "common control," Coyote Station and the Mine would not be deemed under "common control" even under EPA's old policy. Indeed, NDDH all but reached that conclusion in 2013 and 2016.

Under that prior policy, EPA evaluated common control using a "multi-factor" analysis to weigh a number of potential indicators of shared operational decisionmaking. These factors included, but were not limited to, "shared workforces, shared management, shared administrative functions, shared equipment, shared intermediates or byproducts, shared pollution control responsibilities, and support/dependency relationships." Meadowbrook Guidance at 4. The "support/dependency" factor often came into play in cases where one facility could direct or influence the operations of the other, either through control over a critical aspect of operations or through economic leverage. EPA would assess the nature and degree of "influence that these economically or operationally interconnected entities exert (or have the ability to exert) on one another (*e.g.*, the ability to influence production levels)." *Id.* In the past, EPA has often evaluated whether one facility would not be able to operate but for the existence of the other. *See* Letter from Judith M. Katz to Gary E. Graham, "Common Control for Maplewood Landfill, also known as Amelia Landfill, and Industrial Power Generating Corp." (May 1, 2002) (finding no common control, even where one facility was built on property owned by other, because, *inter alia*, either facility could continue to operate if the other were shut down).

At the outset, it is worth noting that North Dakota is home to other mine-mouth lignite-fired electric generating stations with business arrangements similar to those present here, and there is no indication that the Department has deemed any other combination of mine and mine-mouth power plant to be a single source. For example, before CCMC developed its mine a couple of years ago, Coyote Station obtained its fuel from Dakota Westmoreland Corporation's Beulah Mine, which is even closer to the Station than CCMC's mine.

Moreover, in its previous source determination, NDDH determined that these two facilities "do not appear to be under common control," indicating that the Department at least believed it is more likely than not that these are separate sources. 2013 Determination at 2. Nothing about the relationship between Coyote Station and the Mine has materially changed since the NDDH's initial evaluation.

CCMC notified NDDH of the LSA provisions regarding coordination between CCMC and Otter Tail on certain planning activities, including Otter Tail's authority to approve significant capital expenditures. Source Determination Request at 4. NDDH nonetheless determined that neither entity "has decision-making authority over the other" or "is able to direct the management and policies of the other." 2013 Determination at 2. That conclusion was correct: as described above, the LSA does not give Otter Tail authority to direct operations at the Mine, particularly with respect to the Mine's environmental obligations.

There is also not a sufficient "support or dependency" relationship between the two entities to constitute common control under EPA's pre-2018 policy. *See id.* (stating dependency relationship "does not appear to exist"). Applying a "but for" test, Coyote Station does not depend on the Mine because it has already operated for decades prior to the Mine's construction. If the Mine were to close or was somehow unable to satisfy Coyote Station's requirements, Coyote Station could feasibly obtain lignite from other mines in the State. Likewise, the Mine is not entirely dependent on Coyote Station. Pursuant to the LSA, the Mine may sell lignite to Montana-Dakota's Heskett Station, and may sell to third parties so long as Coyote Station's requirements will still be met. LSA ¶¶ 14.2-14.3. In the absence of Coyote Station, CCMC could sell the Mine's lignite on the market in response to demand. *See* 2013 Determination at 2. Finally, the facilities do not share any equipment, facilities, pollution control equipment, workforces, management, security forces, payroll activities, employee benefits, or insurance coverage. Source Determination Request at 6. Although the Mine's coal processing facility transfers lignite from one site to the other, the equipment is not jointly owned: CCMC and Otter Tail have clearly established which entity owns the components necessary for that process.

Finally, the Voigts' assertion that Coyote Station "exerts actual physical operational control" over the coal processing facility and, therefore, the Mine because Coyote Station staff may call Mine staff to inform them of their coal needs for the day borders on the absurd. Voigt Letter at 5 (stating Mine staff "radios to Coyote Station at the start of every shift to determine the Station's coal needs and then he bases his coal crushing activities on what the Station radios back to him"). Of course, what the Voigts describe is the outline of any basic arms-length business transaction: the customer places an order and the seller fills it. The Voigt Letter's argument is akin to saying that a customer who places an order at a fast food drive-in speaker and then receives what she ordered at the window is in control of the restaurant. It goes without saying that a power plant must tell a mine when it needs coal (to generate electricity at the power plant) and when it does not (due to either a scheduled or unscheduled outage at the power plant).

C. Major Industrial Grouping

Using the two-digit classification code, the Mine falls under SIC major group 12 as a coal mine while Coyote Station falls under SIC major group 49 as an electric generating facility. Thus, the sources are not part of the same major industrial grouping.

The Voigts contend the Mine should be considered a "support facility" for Coyote Station and therefore should be grouped under the same SIC code. Voigt Letter at 5-7. The Department considered, but did not resolve, the same argument in its 2013 Determination. 2013 Determination at 3 (stating "the Department is unable to determine at this time if the two sources should be considered to be under the same SIC code"). But for the reasons stated below, designating the Mine as a support facility for Coyote Station would conflict with the expressly stated intent of Congress and EPA and would be inconsistent with the facts.

As part of its 2013 analysis, NDDH cited an EPA guidance document describing a "'50 percent support test' to be used as a presumptive test to determine whether one facility supports the other." *Id.* (citing Memorandum from John S. Seitz to Regional Directors, "Major Source Determinations for Military Installations under the Air Toxics, New Source Review, and Title V Operating Permit Programs of the Clean Air Act" (Aug. 2, 1996) ("Military Guidance")).[7] Under that test, a facility that contributes more than 50 percent of its output or services in support of another would be presumed to be a support facility.

But that test is not required (or even suitable) for all support facility analyses, and it is not appropriate for use here. The Military Guidance itself notes that the 50 percent approach "may not be the most appropriate test in certain situations. Support facility relationships should always be established in light of the particular circumstances of the sources being evaluated." Military Guidance at 17 n.26. Notably, EPA at one time considered adopting the 50 percent output test as the formal regulatory threshold for support facility status, but ultimately rejected that approach. *Compare* 59 Fed. Reg. 44,460, 44515, 44,526 (Aug. 29, 1994) (proposing addition of 50 percent test for support facilities in 40 C.F.R. § 70.2) & 60 Fed. Reg. 20,804, 20,807, 20,829 (Apr. 27, 1995) (proposing addition of 50 percent test in 40 C.F.R. § 71.2); *with* 40 C.F.R. §§ 70.2 & 71.2 (containing no definition or 50 percent threshold test for support facilities). Accordingly, NDDH retains the discretion to determine how to identify support facilities.

The 50 percent output test is not appropriate to apply here because Congress and EPA have already indicated that a mine supplying coal to a nearby power plant should not be considered a support facility, *regardless* of how much of its output goes to that plant. The House Report on the 1990 CAA Amendments cited the same kind of facilities at issue here as its primary example of facilities that should not be aggregated as a single source, stating that EPA's use of the SIC code criterion "avoids the possibility that dissimilar sources, *like a power plant and an adjacent coal mine*, will be considered as the same 'source' because of common ownership." H.R. Rep. No. 101-490(I), at 236-37 (1990) (emphasis added). EPA, in promulgating its Title V regulations, acknowledged Congress's intent and distinguished the coal mine/power plant example from other situations that might warrant aggregation by SIC code. 56 Fed. Reg. 21,712, 21,724 (May 10, 1991).

It is also inappropriate because as outlined by EPA, the 50 percent output test is best suited for determining how to categorize a support facility that serves two or more other facilities. When EPA introduced the SIC Code criterion and the concept of support facilities in its 1980 PSD regulations, it stated that "[w]here a single unit is used to support two otherwise distinct sets of activities, the unit is to be included within the source which relies most heavily on its support." 45 Fed. Reg. 52,676, 52,695 (Aug. 7, 1980). Likewise, the Military Guidance cited by NDDH in its 2013 Determination discussed the 50 percent output test in the context of "situations where an

[7] Available at https://www.epa.gov/sites/production/files/2015-07/documents/dodguid.pdf.

activity (e.g., an airport) supports two or more primary activities under same-entity control (e.g., missile testing/evaluation and pilot training)." Military Guidance at 16. Here, the Department is not evaluating which of several primary activities to aggregate the Mine with as a support facility, but whether the Mine is a support facility at all.

Even if the 50 percent test is the right one to apply here, the Mine would not be considered a support facility of Coyote Station. The 50 percent threshold discussed in the Military Guidance establishes a mere *presumption* of support facility status, which may be rebutted by other evidence. That presumption is overcome here by other evidence that the Mine is not a support facility for Coyote Station. The Voigts strain credulity by arguing that the North Dakota Public Service Commission made an explicit factual finding that "the purpose of the Coyote Creek Mine is to supply coal to Coyote Station" and attributing weight to this finding in the determination whether the Mine and Coyote Station are in the same major industrial grouping. Voigt Letter at 6. In fact, the Commission did not purport to define the Mine's "purpose" or exhaustively list its intended customers: it simply noted the only customer with a sales agreement at the time. As discussed above, the LSA affords CCMC freedom to sell lignite from the Mine to Montana-Dakota's Heskett Station and to other third parties. LSA ¶¶ 14.2-14.3. While it has not done so yet, the Mine is relatively new—having only commenced sales to Coyote Station in 2016.

III. In the Unlikely Event Coyote Station and the Mine Are Determined to be a Single Source, BACT Would Not Have Applied to Any Existing Coyote Station Emission Units.

Finally, the Voigts argue that because the Mine and Coyote Station are allegedly a single source, construction of the Mine "resulted in new emissions exceeding PSD significance thresholds" at that source, and that "[b]oth [Coyote] Station and [the Mine] were therefore required to undergo PSD review, including a determination of best available control technology." Voigt Letter at 8. But even if Coyote Station and the Mine constituted a single source (and they do not, as discussed above), and even if construction of the Mine caused a significant emissions increase and a significant net emissions increase of particulate matter emissions at that combined source,[8] BACT would not have been triggered for any existing Coyote Station emission units.

If the two facilities were considered a single source, then construction of the Mine could have constituted a major modification of an existing major stationary source (Coyote Station), potentially triggering PSD review. *See* 40 C.F.R. § 52.21(a)(2)(ii). In the case of a major modification, BACT is only required for those regulated NSR pollutants for which the project causes a significant net emissions increase (here, particulate matter), and only for the individual emissions units "at which a net emissions increase in the [regulated NSR pollutant] would

[8] The Voigt Letter calculates PSD applicability by citing out-of-context, preliminary estimates of particulate matter ("PM") emissions from the Mine as Otter Tail's official estimates based on final site layout. Voigt Letter at 8. In fact, the estimates the Voigt Letter cites were made early in the conceptual stages of the Mine project, well before it was known where key emission units would be located, and were never updated once the Mine's final design was known. Accordingly, the cited PM emission estimates likely do not represent actual emissions from the project.

occur." *Id.* § 52.21(j)(3). Because the Mine project did not alter any of Coyote Station's existing emissions units, none of those units would be subject to BACT. Accordingly, the Voigts' request for "more stringent limits for the Station" is baseless. Voigt Letter at 8.

Indeed, even if BACT had been applied to the new Mine facilities and the new conveyor, it is unlikely they would have resulted in any different PM emission control requirements than currently exist. Dust suppression techniques—which the Mine is currently required to utilize—*are* likely BACT for the mining operations, the haul roads, and the lignite pile. The Voigts' letter casually suggests BACT would have required the roads to be paved and the lignite pile to be enclosed. Voigt Letter at 8. That is highly unlikely: paving haul roads that are designed for a constant stream of very large and heavy coal haul trucks would be ineffective. Furthermore, enclosing a coal pile of such size would be unprecedented. The coal processing facility and the conveyor are already both subject to NSPS Subpart Y requirements and it is unlikely BACT would have yielded different controls for these facilities.

* * *

If you have any questions about these comments, please do not hesitate to contact me.

Sincerely,

Mark Thoma

Mark Thoma
Manager, Environmental Services

Enclosure

cc: ✓Craig D. Thorstenson, Environmental Engineer, Division of Air Quality

<u>Exhibit 1</u>

Excerpts of Lignite Sales Agreement Between
Coyote Creek Mining Company, L.L.C., and
Otter Tail Power Company, Northern Municipal Power Agency,
Montana-Dakota Utilities Co., and Northwestern Corporation

(Oct. 10, 2012)

WITHOUT LIMITATION, ANY IMPLIED WARRANTY OF MERCHANTABILITY OR OF FITNESS FOR A PARTICULAR PURPOSE OR ARISING FROM A COURSE OF DEALING OR USAGE OF TRADE ARE SPECIFICALLY EXCLUDED AND DISCLAIMED.

5.2 Mining Plans

5.2.1 Life-of-Mine Plan

(a) Seller shall prepare and provide to Buyer in writing a mining plan covering the life-of-mine requirements (the "Life-of-Mine Plan") for the design, development, construction, start-up and operation of the Mine, including the Development Period, the Production Period and the Post-Production Period to furnish from the Reserves the lignite requirements of Buyer under this Agreement. Seller's initial Life-of-Mine Plan shall assume that Buyer's life-of-mine lignite requirements shall be equal to 2,500,000 Tons per Year unless Buyer notifies Seller to use a different assumption. The Life-of-Mine Plan shall be based on the principle of recovering the most economic reserves from within the Reserves over the Term. The Life-of-Mine Plan shall be prepared in accordance with sound engineering and design practices and Applicable Laws and shall include, but not be limited to, production schedules, staffing and equipment requirements, estimated costs per Ton using the cost categories identified in Section 7, a property acquisition plan, schedule and estimated budget, a mine development plan, schedule and budget, method of operation, anticipated lignite quality characteristics, reclamation and permitting schedules, estimated capital budget containing estimates of all capital expenditures, commitments, and loan/lease requirements, operating cost estimates, mine design, mine projection maps, mine progression and reserve studies, and other documentation reasonably requested by Buyer. Seller will permit Buyer's representatives to participate in the development of the Life-of-Mine Plan and any revisions thereto.

(b) The Life-of-Mine Plan shall be completed and delivered by Seller to Buyer within three hundred sixty-five (365) Days of the Effective Date. Buyer shall review the Life-of-Mine Plan for reasonableness and completeness. Within sixty (60) Days of receipt of the Life-of-Mine Plan, Buyer shall meet with Seller to jointly review the proposed Life-of-Mine Plan. Within forty-five (45) Days of the conclusion of such review, Buyer shall provide notice to Seller of Buyer's approval of, or Buyer's suggested modifications to, the proposed Life-of-Mine Plan. If Buyer suggests modifications to the proposed Life-of-Mine Plan, Buyer shall advise Seller of the reasons for such modifications, and Buyer and Seller shall meet promptly and attempt in good faith to resolve their differences with respect to the proposed Life-of-Mine Plan. If Buyer and Seller are unable to resolve such differences within thirty (30) Days after Buyer proposes such modifications, Seller shall revise and resubmit the proposed Life-of-Mine Plan as requested by Buyer.

5.2.2 Annual Mining Plan

(a) On or before July 1 of each Year during the Term, including the Development Period, the Production Period and the Post-Production Period, Seller shall provide to Buyer in writing (or in electronic format) a detailed mining plan covering the operation of the Mine for the next Year (the "Annual Mining Plan") that conforms substantially to the Life-of-Mine Plan. If Buyer and Seller agree that current circumstances require that the Annual Mining Plan differ in any material respect from the Life-of-Mine Plan, Seller shall review and revise, if necessary, the Life-of-Mine Plan based on the then-current circumstances including the designation of annual deliveries provided by Buyer in the notice given pursuant to Section 2.6. Seller shall provide documentation of such revised Life-of-Mine Plan consistent with the requirements of Section 5.2.1.

(b) Such Annual Mining Plan shall include, but not be limited to, the following items for activities during the following Year:

(i) maps showing planned mine progression, location of infrastructure, and capital project locations;

(ii) mining operations schedules showing acres disturbed, overburden removed, lignite recovered by seam, anticipated lignite quality by seam, equipment working schedules, and labor requirements;

(iii) a reclamation plan showing areas to be regraded, planted or otherwise subject to reclamation activities and a permitting and bonding schedule;

(iv) an estimated capital budget containing detailed, itemized estimates of all capital expenditures, commitments, and loan/lease requirements, including indicative terms for any proposed acquisition of Capital Assets by Seller;

(v) an estimate of all operating costs and expenses in such detail as required to estimate the Cost of Production under Section 7.2(a), along with estimated employee headcounts and such other information as Buyer may reasonably request;

(vi) an estimated Monthly cash flow statement containing estimates of the cash requirements for the capital and operating budgets prepared pursuant to this Section 5.2.2;

(vii) a projection of the next four Years of operations in such detail as directed by Buyer, which shall include assumptions as to lignite stockpile size(s) and location(s), if any; and

(viii) such other information as directed by Buyer.

5.2.3 Approval of Annual Mining Plan

(a) Within sixty (60) Days after receipt by Buyer of an Annual Mining Plan, and, if applicable, a revised Life-of-Mine Plan, Buyer shall give Seller notice of Buyer's approval or disapproval of such Annual Mining Plan (including specific approval of any acquisition of Capital Assets by Seller) and, if applicable, revised Life-of-Mine Plan.

(b) If Buyer does not give Seller such notice within sixty (60) Days after Buyer's receipt thereof, Buyer shall be deemed to have approved such mining plan(s).

(c) If Buyer disapproves an Annual Mining Plan or any portion(s) thereof, Buyer shall advise Seller of the reasons for such disapproval, and Buyer and Seller shall meet promptly, but no more than ten (10) Business Days after such disapproval was expressed, and attempt in good faith to resolve their differences with respect to the Annual Mining Plan. If Buyer and Seller are unable to resolve such differences within such ten (10) Business Days, Seller shall adopt such changes to the Annual Mining Plan as requested by Buyer, and shall submit a revised Annual Mining Plan within ten (10) Business Days following the failure of Buyer and Seller to resolve such differences.

5.2.4 Mine Development and Operation

(a) Seller shall consult with and keep Buyer informed of the progress of Seller's activities related to the Mine during the Term in such manner as Buyer may reasonably request.

(b) Buyer and Seller shall meet quarterly (or at such other times as needed or requested by either Party) to review the progress of Seller's activities related to the Mine during the Term.

(c) Seller shall not make any capital expenditures unless they are generally reflected in a capital budget approved by Buyer as part of an Annual Mining Plan or unless otherwise specifically approved by Buyer; provided, however, Seller shall have the right during any Year to make capital expenditures required in the event of an Emergency without advance approval by Buyer. If the nature of the Emergency and the time elements involved do not allow sufficient time to obtain Buyer's approval of such capital expenditure before it is incurred, Seller shall subsequently and promptly (but not later than two Business Days after such occurrence) give Buyer notice thereof.

(d) Seller shall have the right, without the specific written approval of Buyer, to exceed the amount for any <u>specific</u> capital expenditure in any budget approved by Buyer by up to five percent (5%), provided that in no event shall any such excess expenditure exceed One Hundred Thousand Dollars ($100,000) (the "<u>CapX Cap</u>") (subject to adjustment pursuant to <u>Section 9</u>) or such other amount as mutually agreed to by the Parties in any Year. If Seller desires Buyer's approval to exceed a specific line item, budgeted, capital expenditure by more than five percent (5%) or more than the CapX Cap or such other amount as mutually agreed to by the Parties in any Year, Seller shall make such request by written notice as soon as practicable, and if Buyer neither approves nor disapproves such request within

(b) an amount equal to the total sum of all overhead costs (excluding labor costs covered by paragraph (a) above) actually incurred by Seller during the Development Period in connection with the design, permitting, development, construction, equipping and start-up of the Mine, which costs shall include, but not be limited to, costs of materials and supplies, costs related to the maintenance of leases, subleases and fee ownership of lands and reserves in the South Beulah Area of Interest, reasonable travel expenses, equipment rental costs, computer service costs, allocated office expenses, fees and expenses of outside consultants and legal counsel, administrative and general expenses of Seller directly allocable to the Mine, and any other reasonable costs which are not covered by paragraphs (a) and (c) of this Section 7.1.2;

(c) an amount equal to Seller's Loan and Lease Obligations due and payable during the Development Period;

(d) an amount equal to depreciation and amortization charges on Capital Assets acquired by Seller during the Development Period to which Seller is entitled and the rates of which shall be determined by Seller in accordance with GAAP, and ad valorem or similar taxes incurred by Seller during the Development Period;

(e) the Capital Charge (as defined in Section 7.2(d)) payable each Year during the Development Period on the Invested Capital of Seller;

(f) a fee equal to [redacted] per Month (the "Development Fee"), which amount shall be subject to adjustment pursuant to Section 9; and

(g) the Pre-LSA Costs.

7.1.3 Seller shall report current Development Period Costs to Buyer Monthly during the Development Period and at the conclusion of the Development Period.

7.1.4 All Development Period Costs shall be capitalized as incurred during the Development Period. All Development Period Costs other than the Development Fee and the Capital Charge shall be amortized on a straight-line basis in equal Monthly installments over the full term of the Production Period by being included in the Cost of Production. The Development Fee and the Capital Charge incurred during the Development Period shall be amortized on a straight-line basis in equal Monthly installments over the first fifty-two (52) Months of the Production Period by being included in the Cost of Production during such Months.

7.2 Compensation During the Production Period

During the Production Period, Buyer shall pay Seller in accordance with Section 8 an amount that equals the sum of (i) the Cost of Production (Section 7.2(a)), (ii) the Agreed Profit payable to Seller (Section 7.2(c)(i)) and (iii) the Capital Charge (Section 7.2(d)). All amounts payable by Buyer during the Production Period under this Section 7.2 shall constitute "Compensation" during the Production Period. Buyer acknowledges that when no lignite is mined, processed, sold or delivered during the Production Period, Buyer shall continue to pay the Capital

Charge and the portion of the Cost of Production that is incurred by Seller in accordance with the terms of this Agreement and invoiced to Buyer even when lignite deliveries are not made (referred to by the Parties as "period costs," as opposed to "product costs," which are not invoiced when lignite deliveries are not made).

(a) Cost of Production

For the purposes of this Agreement and except as otherwise expressly stated, "Cost of Production" shall mean all costs actually incurred by Seller performing its obligations under this Agreement during the Production Period, including, without limitation, costs related to the mining, processing and delivering of lignite from the Mine, but shall exclude costs or expenses not authorized pursuant to this Agreement or that have been incurred over the prior disapproval by Buyer thereof. Any costs incurred by an Affiliate of Seller and charged to Seller shall be included only at the cost to such Affiliate without addition for any intercompany profit or service charge. Seller, in determining costs, shall give Buyer the proportionate benefit of volume purchases participated in by Seller and Affiliates of Seller. The Cost of Production shall be determined on an accrual basis in accordance with GAAP, and shall include, but shall not be limited to, the following:

(i) All production, maintenance and delivery costs incurred by Seller in the performance of its obligations under this Agreement during the Production Period including, without limitation, the following types of costs:

(aa) Labor costs for work directly related to the Mine, which include, without limitation, (i) wages (e.g., regular and overtime wages paid to non-exempt employees and workforce, and salaries paid to exempt employees), (ii) the costs of all related payroll taxes (e.g., federal social security and Medicare taxes, federal and state unemployment taxes and workers compensation) and fringe benefits, including, without limitation, welfare plans, contributions to 401(k) and other retirement plans, contributions to defined benefit and defined contribution pension plans, group insurance (e.g., medical, dental, term life and disability), holidays, floating holidays, vacation days, military duty days, jury duty days, bereavement days, personal days, sick days, severance, and other comparable benefits paid to or for employees of Seller and Affiliates of Seller, (iii) reasonable travel costs and lodging costs for employees of Seller and Affiliates of Seller, and (iv) the costs of employee productivity, safety and environmental incentive plans;

(bb) Expense of payroll preparation, general accounting and billing performed at the Mine;

(cc) Consumable materials and supplies;

(dd) Consumable tools;

(ee) Costs of machinery and equipment that are not Capital Assets, including rental costs;

(ff) Rental of machinery and equipment not included in Seller's Loan and Lease Obligations;

(gg) Electric power and other utility costs;

(hh) Reasonable and necessary services incurred in the mining, processing or delivery of lignite from the Mine rendered by persons other than employees of Seller and Affiliates of Seller that are directly charged to the Mine;

(ii) Insurance premiums and deductibles, including in respect of workers' compensation as required by law, liability, property damage, and such other insurance as requested by Buyer and in amounts and with insurance carriers (or self-insurance) approved by Buyer, as provided in Section 10;

(jj) All taxes and fees, including, without limitation, ad valorem, severance, sales, use, property, excise, license, stamp or other taxes, levies, imposts, duties, charges, or fees of any nature, but not including income taxes, imposed by any Governmental Entity;

(kk) Fees, assessments and penalties payable to MSHA and other Governmental Entities; provided, however that to the extent a Governmental Entity has determined that any such fees, assessments or penalties are the result of Seller's gross negligence or willful misconduct, such fees, assessments or penalties shall not constitute Cost of Production and shall be paid by Seller and not reimbursed by Buyer;

(ll) Cost of reclamation during the Production Period, including labor and supplies, as required to comply with all Applicable Laws and leases and subleases of Reserves;

(mm) Costs incurred by Seller relating to this Agreement in connection with or as a result of the enactment, modification, interpretation, repeal or enforcement of any Applicable Laws;

(nn) Usual membership fees of the National Mining Association (allocated to the Mine pro rata based on combined annual coal production of Seller and its Affiliates in the United States of America, or such other pro rata method utilized by the National Mining Association in charging all of its members), and a reasonable number of other professional, service and civic organization memberships paid for by Seller which are commonly maintained by surface mining companies similarly situated in

North Dakota, and such other contributions and memberships approved in advance by Buyer;

(oo) Costs incurred by Seller (i) related to the maintenance of leases, subleases and fee ownership of lands and reserves in the South Beulah Area of Interest, such costs to include all sums actually paid by Seller as rental, advance royalty, landman services, abstract and title opinion and curative costs incurred to confirm or obtain clear title to the Reserves, and recordation fees; provided, however, that Seller or its Affiliate shall directly pay lease bonuses and labor costs expended in connection with the acquisition of leases and such lease bonuses and labor costs shall not constitute Cost of Production; (ii) in payment of production royalty or overriding production royalty attributable to lignite sold to Buyer hereunder which is produced from lignite and other coal leases or other mining rights covering and affecting the Reserves; and (iii) in connection with the acquisition of fee property for the Mine office, Mine haul roads to the Plant facilities and other Mine facilities and infrastructure;

(pp) Costs related to permits and permitting at the Mine;

(qq) Costs of Mine security;

(rr) Corporate franchise taxes for Seller paid to the State of North Dakota related to the Mine, if any;

(ss) Costs of drilling and geological services;

(tt) Costs related to sampling, analyses, surveying and weighing lignite, and the testing of the Sampling System and the scales pursuant to Section 11;

(uu) Costs of Audits, and any other outside audits approved in advance by Buyer;

(vv) Costs related to Seller's compliance with its obligations under Section 12;

(ww) Costs incurred as the result of labor organization activities or unionization of Seller's employees at the Mine (including, without limitation, costs of arbitration and labor and other costs incurred by Seller in connection with any collective bargaining activities or agreements);

(xx) Cost of reclamation bonds and similar performance bonds as required by Applicable Laws and obtained by Seller in connection with the performance of its obligations hereunder;

(yy) Post-Mining Reclamation Costs payable as determined pursuant to GAAP requirements, including costs related to the Reclamation Account; and

(zz) Mine administrative costs including telephone and office costs, travel expenses and moving expenses of exempt employees of Seller, provided that no moving expense will be allowed for any non-exempt employee of Seller without Buyer's prior approval.

There shall be credited to costs under this Section 7.2(a) amounts equal to (1) any investment tax credit or other tax credits based upon new investment incurred and taken by Seller or by an Affiliate of Seller that is attributable to Seller's operation, and (2) any refunds or rebates received by Seller from manufacturers or vendors and (3) the proceeds from any insurance policies obtained in accordance with Section 10, except to the extent Seller or its Affiliates use such proceeds to pay any losses, costs, fees, expenses, damages or liabilities incurred by Seller or its Affiliates that result from or relate to an insured loss or occurrence, including but not limited to costs to repair or replace equipment or other property, or amounts to pay stipulated loss values under equipment leases.

(ii) Depreciation and/or amortization charges on Capital Assets to which Seller is entitled, the rates of which shall be determined by Seller from time to time in accordance with GAAP. Unless otherwise agreed by Buyer and Seller, the rates of such depreciation and/or amortization shall be limited to a straight-line basis over the anticipated useful service life of the Capital Assets. Buyer may correct from time to time anticipated useful service lives to conform to experience. Net gains or losses on the dispositions of Capital Assets shall be credited or charged, as the case may be, to the Cost of Production. Transactions involving Capital Assets between Seller and any one or more of its Affiliates (including contributions to the capital of Seller) shall be reflected in Seller's accounts at cost to the Affiliates of the Capital Assets involved, less accumulated depreciation, as shown by the accounts of the transferring company, or salvage value if it is greater than depreciated cost.

(iii) All Seller's Loan and Lease Obligations due and payable during the Production Period.

(iv) All Development Period Costs accrued during the Development Period, which shall be repaid on a Monthly basis during the Production Period as part of the Cost of Production, as provided in Section 7.1.4.

(b) **[Intentionally Omitted.]**

(c) Agreed Profit

(i) During the Production Period for all lignite sold and delivered by Seller to Buyer hereunder from the Mine, the agreed profit ("Agreed Profit"), expressed in 2011 dollars, shall be [redacted] per Ton; provided, however, that Agreed Profit shall not be paid in respect of Non-conforming Lignite.

(ii) General and administrative costs that are to be covered by the Agreed Profit (and that shall not otherwise be included in the Cost of Production) during the Production Period, are salaries and related expenses such as payroll taxes, pensions, contributions to retirement plans, other fringe benefits and workers' compensation, together with travel, telephone, postage and office rent and office maintenance expense, of executive officers of Seller not located at the Mine and of officers of Affiliates of Seller who perform, and for the time and to the extent they perform, functions relating to the Mine or this Agreement. Without limiting the generality of the foregoing, the expenses of executive office support, administrative support, operations management support, business development support and legal support (excluding outside litigation services and other outside legal services described below in Section 22.7), finance and accounting support, management information systems support, human resources support and benefits support rendered by employees of Affiliates of Seller shall be covered by the Agreed Profit.

(iii) Notwithstanding anything to the contrary contained in Section 7.2(c)(ii), general and administrative costs that are not to be covered by the Agreed Profit and that otherwise shall be included in the Cost of Production are:

(aa) corporate franchise taxes for Seller paid to the State of North Dakota related to the Mine, if any;

(bb) litigation and other legal expenses directly related to activities under this Agreement incurred through the use of attorneys who are not employees of Seller or Affiliates of Seller, excluding the cost of any litigation or action in which Seller and Buyer are on opposing sides, and excluding the cost of arbitration under Section 18;

(cc) actual costs of new reserve mine planning and special studies provided by employees of Seller or Affiliates of Seller not located at the Mine and specifically approved in advance by Buyer;

(dd) actual costs of mine permitting, geologic support on drilling and modeling provided by employees of Affiliates of Seller not located at the Mine, and specifically approved in advance by Buyer; and

(ee) labor cost and related taxes and fringe benefits for employees of Seller and Affiliates of Seller who are not located at the Mine but whose labor and associated benefit costs are properly charged directly to the Mine with Buyer's advance approval.

(d) Capital Charge. Buyer shall pay to Seller an amount equal to [redacted] of the sum of (i) Seller's Invested Capital and (ii) the unamortized/undepreciated amount of Development Period Costs (the "Capital Charge"). The Capital Charge shall be paid Monthly by Buyer and shall be included in the invoices provided for in Section 8.1.

7.3 Payment of Post-Mining Reclamation Costs During the Post-Production Period

Seller shall first pay Post-Mining Reclamation Costs out of the Reclamation Account. In the event that the Reclamation Account does not contain sufficient funds to obtain the release of the Mine reclamation bond from the North Dakota Public Service Commission, Buyer shall promptly pay to Seller the additional required Post-Mining Reclamation Costs, including all costs and expenses of demobilization, equipment modification and employee relocation. In the event that funds remain in the Reclamation Account after final release of the Mine reclamation bond from the North Dakota Public Service Commission, Seller shall promptly pay such remaining funds to Buyer. Seller shall not require Buyer to pay Seller any profit for services performed by Seller in final mine closing and reclamation during the Post-Production Period.

Section 8. ***Billing and Payment; Audit True-Up***

8.1 Monthly Invoices

(a) On or before the tenth (10^{th}) Day of each Month, Seller shall furnish Buyer with a written invoice which sets forth the amount due Seller under Section 7 for the immediately preceding Month. The Monthly invoices shall be in such form and detail as reasonably requested by Buyer and shall list the quantity of lignite delivered to the Delivery Point. Seller shall furnish promptly evidence substantiating the invoice as Buyer may reasonably request.

(b) Buyer shall pay Seller the amount of such invoice within ten (10) Days of Buyer's receipt of the same by wire transfer to an account designated by Seller in writing in immediately available federal funds.

(c) If Buyer disagrees with the amount of any invoice, Buyer shall immediately notify Seller of such disagreement so that the difference may be resolved before the date payment for such invoice is due. If Buyer fails to give such notification, or if Buyer and Seller determine the invoiced amount is correct or that another amount is correct before the date payment is due, such invoice shall be paid in full or in the amount agreed as correct by Buyer and Seller. If Buyer gives such notification and Buyer and Seller do not resolve such disagreement before the date payment is due, Buyer shall pay the amount of the invoice on the date payment is due. If Buyer and Seller are not able to resolve the dispute within thirty (30) Days following the date on which the disputed payment was due, the Parties shall resolve the dispute by arbitration pursuant to the provisions of Section 18. Payment or payments under this Section 8 shall not be deemed a waiver of any rights of Buyer to have the invoice hereunder corrected or an

(d) All audit exceptions, payment corrections, or other matters identified in audits or reviews of books and records shall be resolved by mutual agreement of the Parties, and corrections, credits or additional charges shall be included in the next regular Monthly invoice.

12.3 Periodic Inspections

(a) Buyer shall, upon reasonable notice and in accordance with the requirements of Applicable Law, be afforded complete access to the Mine and to copies of any of Seller's accounting and financial records, exploration data, geologic assessments, environmental and permitting materials, engineering studies, surveys, operational and maintenance records, reports, financial summaries, Reclamation Account Documentation and any other documents applicable to or associated with the Mine or the performance by Seller of its obligations under this Agreement, subject to any Applicable Laws or Seller policies regarding employee records. Prior to entering the Mine site, any Buyer's representative shall check in with appropriate personnel at the entrance to the Mine site and access shall be allowed unless Seller determines such access would interfere with or disrupt Seller's performance hereunder, in which case access shall be granted as soon as practicable thereafter. Such inspection shall not be for any purpose or reserved right of controlling the methods and manner of the performance of the work by Seller under this Agreement, but shall be to assure Buyer that Seller is performing its obligations under this Agreement.

(b) Seller agrees to maintain adequate books, payrolls and records satisfactory to Buyer in connection with work performed and payments made by Seller under this Agreement. Buyer and its duly authorized representatives shall have access at all reasonable times to the books, payrolls, records, correspondence and personnel of Seller relating to any of the work performed hereunder for the purpose of auditing and verifying the amounts charged by Seller or for any other reasonable purpose including, but not limited to, compliance by Seller with any of the terms and provisions of this Agreement.

Section 13. ***Force Majeure***

13.1 General

If either Party is rendered unable, wholly or in part, by Force Majeure (as hereinafter defined) to carry out any of its obligations under this Agreement, and if within five (5) Business Days after the Party experiencing a Force Majeure is aware of the occurrence of such Force Majeure provides notice, including a detailed explanation of such Force Majeure, to the other Party, then the obligations of the Party giving such notice shall be suspended to the extent made necessary by such Force Majeure from the inception of the Force Majeure and during its continuance, but for no longer. The Party giving such notice shall diligently use its best efforts to eliminate the cause and effect of such Force Majeure insofar as possible with all reasonable dispatch. Any deficiencies in the production or delivery of lignite hereunder caused by Force Majeure shall not be made up under the provisions of this Agreement except by mutual agreement. No such event of Force Majeure shall excuse, alter or diminish the obligation of Buyer to make the payments provided for in Section 7 in accordance with Section 8. Notwithstanding anything to the contrary herein, this Agreement may, subject to Section 16.3, be terminated by Buyer if a Force Majeure affecting Seller and its effect are not eliminated within thirty (30) months from inception of such Force Majeure.

13.2 Definition

The term "Force Majeure" as used in this Agreement shall mean any and all causes beyond the reasonable control of the Party failing to perform, such as acts of God, strikes or other industrial disturbances, material shortages, labor organizing efforts, acts of the public enemy, wars, blockades, insurrections, riots, acts of terrorism, epidemics, pandemics, landslides, adverse geological or hydrological conditions, faults in lignite seams, lightning, hurricanes, tornadoes, earthquakes, fires, storms, floods, washouts, major breakdowns of or damage to Plant or Mine facilities (including haul roads between the Mine and the Plant), Plant or Mine equipment, interruptions to or contingencies of transportation, orders or acts or refusals to act by a governmental, military or civil authority (including without limitation, interruptions, whether by action or inaction, by federal, state or local governments or court orders, present and future, or acts or failures to act of any Governmental Entity having proper jurisdiction) and any other causes, whether of the kind herein enumerated or otherwise, beyond the reasonable control of the Party failing to perform, that wholly or partly prevent the mining, producing, processing and delivering of the lignite by Seller or the receiving and/or utilizing of the lignite by Buyer. The settlement of strikes or industrial disputes or disturbances or the resolution of labor organizing efforts shall be entirely within the discretion of the Party whose employees are affected, and the above requirement that any Force Majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or the resolution of labor organizing efforts by acceding to the demands of the opposing party therein when such course is inadvisable in the discretion of the Party having the difficulty. A decrease in or lack of demand for electricity from Plant shall not constitute Force Majeure.

13.3 Replacement Fuel During a Force Majeure Affecting Seller

Seller shall use reasonable best efforts to identify and arrange for the sale to Buyer of replacement fuel meeting the Quality Requirements during the continuance of a Force Majeure which prevents Seller from delivering lignite to Buyer. Buyer shall be solely responsible for the costs of identifying, arranging for the sale to Buyer of, and paying for, all such replacement fuel.

Section 14. ***Acquisition of Additional Reserves; Sales to Heskett Station; Sales to Third Parties***

14.1 Acquisition of Additional Reserves

Seller shall have the exclusive right to acquire additional reserves in the South Beulah Area of Interest. Buyer agrees that it and its Affiliates shall not acquire any interest in real property or minerals in the South Beulah Area of Interest during the Term, without Seller's prior written consent.

14.2 Sales to Heskett Station

Seller shall have the right to sell lignite from the South Beulah Area of Interest to Montana-Dakota or its Affiliates for use at the Heskett Station generating facility near Mandan, North Dakota ("Heskett Sales"). Any Heskett Sales shall be made on terms agreed to by Buyer, Seller and Montana-Dakota, with Seller receiving its Costs of Production, Capital Charge and Agreed Profit on all Tons sold in Heskett Sales.

14.3 Sales to Third Parties By Seller

In addition to the right to make Heskett Sales as provided in Section 14.2, Seller shall have the right to sell lignite from the South Beulah Area of Interest to third parties. Prior to making any such sales, (i) Seller shall deliver to Buyer evidence that third-party sales proposed by Seller shall not prevent Seller from performing its obligation to deliver lignite to Buyer hereunder and (ii) Seller and Buyer shall promptly meet to determine the sales price of such lignite and the manner in which the proceeds from such sales will be split between Seller and Buyer.

14.4 Seller Contributions to the Reclamation Account

In the event that Seller sells lignite from the South Beulah Area of Interest in Heskett Sales or to third parties, Seller shall (a) determine the amount of Post-Mining Reclamation Costs that are attributable to such sales in accordance with the terms of Section 5.3.1, (b) deposit such amount from the proceeds of such sales into the Reclamation Account within ten Days of receipt of the purchase price of the lignite so sold and (c) use the funds held in such account solely for purposes of performing final Mine closure and reclamation during the Post-Production Period.

14.5 Sales to Third Parties By Buyer

Buyer shall have the right to resell lignite purchased from Seller for use at the Plant to third parties. In the event that Buyer resells lignite to third parties, Seller shall be paid the Compensation payable under this Agreement for the Tons to be resold, and Buyer shall retain the additional profit, if any, on such Tons when they are resold.

14.6 Termination of Right to Make Third-Party Sales

Unless otherwise agreed to by Buyer and Seller, neither Buyer nor Seller may commit to sell, or sell, lignite from the South Beulah Area of Interest to third parties or as Heskett Sales with a delivery date after December 31, 2040 or such later date to which the Production Period shall have been extended in accordance with Section 2.1(f).

Section 15. *Defaults; Remedies*

15.1 Seller Default

For the purposes of this Agreement, any one of the following events is a "Seller Default":

(a) if there exists at any time more than six months after the Production Date, and for any reason attributable to Seller (excluding Force Majeure), any shortfall in delivered Tons of lignite that is more than thirty percent (30%) of the Tons

April 11, 2013 Stationary Source Determination

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

MEMO TO : File
Coyote Creek Mining, LLC
Mercer County, North Dakota

FROM : Craig D. Thorstenson
Environmental Engineer
Division of Air Quality

CDT

RE : Stationary Source Determination

DATE : April 11, 2013

A letter dated February 13, 2013 (attached) from Coyote Creek Mining Company, LLC (CCMC) requests a stationary source determination from the Department regarding a proposed lignite mine to be known as the Coyote Creek Mine (CCM). In their letter, CCMC requests a determination as to whether emissions from the Coyote Station electric generating plant and the CCM must be aggregated when determining applicability of the Prevention of Significant Deterioration of Air Quality (PSD), 1990 Clean Air Act Amendments Section 112 air toxics and Title V (Part 70) operating permit programs. The federal PSD, Section 112 and Title V requirements are incorporated into the North Dakota Air Pollution Control Rules and the Department has primary responsibility for implementing the requirements in the state of North Dakota in areas which are not located on Indian Reservations. On Indian Reservations in North Dakota the U.S. Environmental Protection Agency (EPA) has primary responsibility for implementing the above programs.

The applicable regulations consider a stationary source, or group of sources considered together, to be a major source if the stationary source (or group of sources) is located on one or more contiguous or adjacent properties and is under "common control" of the same person (or persons under common control). In addition, under PSD and Title V, the sources must be under the same industrial grouping (SIC code) to be considered part of the same stationary source.

Contiguous or Adjacent Properties Criteria

The CCM and the Coyote Station will be located on property which is over three miles apart with the property between the two sources not controlled by either party. It is determined that the two sources are not located on contiguous or adjacent properties.

Common Control Criteria

The criteria used to determine if two sources are under "common control" are outlined in the February 13, 2013 letter from CCMC. EPA guidance regarding common control includes the following:

- September 18, 1995 letter from EPA Region VIII to the Iowa Department of Natural Resources (available at: http://www.epa.gov/region07/air/title5/t5memos/control.pdf).
- October 1, 1999 letter from EPA Region VIII to the Colorado Department of Public Health (available at: http://www.epa.gov/region7/air/nsr/nsrmemos/frontran.pdf).

Common control can be established through ownership; in this case, there is no common ownership. Common control can also be established if one entity has decision-making authority over the other (through contractual agreement, etc.); in this case, neither entity has decision-making authority over the other. Operational decisions at CCM and the Coyote Station will be made separately.

EPA has not defined "control"; however, EPA guidance references the Securities and Exchange Commission (SEC) definition of "control". The SEC definition of "control" is as follows:

> Control means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person (or organization or association) whether through the ownership of voting shares, contract, or otherwise.

Neither entity (CCMC or the owners of the Coyote Station) is able to direct the management and policies of the other; therefore, the SEC definition of control is not met.

In addition to the above, common control can be established if there is a support or dependency relationship between the two entities such that one facility cannot continue to operate if the other shuts down. EPA guidance also references a "but for" test (i.e., one would not exist "but for" the other) which can be considered when determining if two entities are under common control. When determining the extent of the support or dependency relationship, the following were considered:

- The Coyote Station is not dependent on the CCM as the Coyote Station has operated since 1981 without the CCM.
- CCMC will likely enter into a long-term contract to supply coal from the CCM to the Coyote Station; however, CCMC is free to sell coal to third parties.
- The Dakota Westmoreland Beulah Mine currently supplies coal to the Coyote Station and it appears that the Beulah Mine will stay open even if the agreement to supply coal to the Coyote Station is not renewed.
- The CCM does not produce a specific product that can only be utilized at the Coyote Station. Demand for coal (and not the CCM relationship with the Coyote Station) is expected to be a major factor in the viability of the CCM if the Coyote Station shuts down.

Based upon the above, there is a reasonable possibility that each facility could continue to operate if the other facility were to shut down. Therefore, a support or dependency relationship does not appear to exist to such an extent that the two facilities should be considered to be under common control.

Based upon the above, the CCM and the Coyote Station do not appear to be under common control.

SIC Code Criteria

CCM is a coal mine in SIC major group 12, while Coyote Station is under SIC major group 49. However, an August 2, 1996 EPA memorandum (available at: http://www.epa.gov/ttn/caaa/t5/memoranda/dodguid.pdf) has established that "support" activities must be aggregated with the associated "primary" activity regardless of dissimilar SIC codes. The August 2, 1996 memorandum discusses a "50 percent support test" to be used as a presumptive test to determine whether one facility supports the other. Although this document is intended for determinations at military facilities, the language relating to support facilities can be applied to non-military facilities.

The above-referenced August 2, 1996 memorandum states that "a support facility usually would be aggregated with the primary activity to which it contributes 50 percent or more of its output". The document adds a footnote stating, "However, while the 50 percent support test is the presumptive test for these programs, it may not be the most appropriate test in certain situations. Support facility relationships should always be established in light of the particular circumstances of the sources being evaluated".

If greater than 50 percent of the coal mined at CCM will be supplied to the Coyote Station, then CCM may be presumed to be a support facility for the Coyote Station and the facilities would be considered classified under the same SIC code for purposes of the PSD and Title V rules. It should be noted that the Coyote Station has been in operation for many years without the CCM; however, it is unknown what percentage of the coal mined at CCM will be supplied to the Coyote Station.

Given the uncertainties regarding the amount of coal to ultimately be supplied from CCM to the Coyote Station, the Department is unable to determine at this time if the two sources should be considered to be under the same SIC code.

Conclusion

Two sources must satisfy the first two above-referenced criteria (be on contiguous or adjacent property and be under common control) to be considered the same stationary source under the Section 112 air toxics program. In addition to the first two criteria, two sources must satisfy the third criteria (belong to the same SIC code or have a support facility relationship) to be considered the same stationary source under PSD and Title V programs.

The Coyote Creek Mine and the Coyote Station do not appear to be under common control and it is unclear if the two sources should be considered under the same SIC code. However, the two sources are not located on contiguous or adjacent properties. Since the two sources are not located on contiguous or adjacent properties, the sources are considered separate sources for purposes of determining whether the sources are subject to the requirements of the above programs.

CDT:saj
Attach:

COYOTE CREEK MINING COMPANY, L.L.C.

A SUBSIDIARY OF THE NORTH AMERICAN COAL CORPORATION

2000 Schafer Street, Suite D
Bismarck, ND 58501-1204
(701) 258-2200 • Fax (701) 222-7594
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February 13, 2013

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue
Bismarck, ND 58501-1947

RE: Coyote Creek Mining Company, L.L.C.'s Proposed Lignite Mine, Separate Stationary Source Determination Request

Dear Mr. O'Clair:

Coyote Creek Mining Company, L.L.C. (CCMC) respectfully requests a stationary source determination from the North Dakota Department of Health (NDDH) regarding its proposed lignite mine, Coyote Creek Mine (CCM). This submittal describes the proposed operations at the CCM and requests an express determination from the NDDH that the proposed mine is a separate "stationary source" from the Coyote Station electric generating plant under Prevention of Significant Deterioration (PSD) rules, Section 112 of the Clean Air Act (CAA) for hazardous air pollutants (HAP), and Title V (Part 70) rules. These Federal programs are incorporated into the North Dakota Air Pollution Control Rules under Chapters 33-15-15, 33-15-22, and 33-15-14, respectively.

Executive Summary

CCMC has evaluated the applicable regulations and corresponding criteria of the aforementioned CAA programs in determining the stationary source status of the proposed CCM in relationship to the existing Coyote Station. The implementing regulations require that a stationary source, or group of stationary sources, that are located within a contiguous area and under common control be considered together for purposes of determining if the combined HAP emissions meet major source thresholds.[1] Major source determinations under the PSD and Title V programs also require that sources be aggregated on the basis of the same industrial grouping as determined by the two-digit major group Standard Industrial Classification (SIC) code.[2] These three criteria (contiguous or adjacent property, common control, industrial grouping) are applied to pollutant-emitting activities at the CCM and Coyote Station. Both of the first two criteria must be met for purposes of aggregating HAP emissions under Section 112. All three criteria must be met for the pollutant-emitting activities to be aggregated for PSD applicability purposes.

[1] See definition of "major source" under Section 112(a)(1) of the CAA as promulgated at 40 CFR § 63.2.

[2] See definition of "major source" at 40 CFR §70.2 and at NDAC 33-15-14-06.1.q. for the Title V operating permit program. See also definition of "building, structure, facility, or installation" at 40 CFR § 52.21(b)(6) as referenced in NDAC 33-15-15-01.2. Herein, references to PSD rules will be denoted from the EPA regulations at 40 CFR § 52.21.

CCMC will be conducting its mining operations at a distance of at least 3 miles from Coyote Station. The CCM and Coyote Station are separately owned and are under separate control. Further, each facility will operate under a different major group SIC code. Under applicable law, the CCM and Coyote Station should be regarded as separate stationary sources for CAA purposes.

Description of Proposed Coyote Creek Mine

The CCM shall be designed as a surface mining operation with annual production of approximately 2.5 million tons of lignite for sale. The primary mining operations are proposed to occur in a 13-square- mile area located 3 to 4 miles southwest of Coyote Station and west-southwest of Dakota Westmoreland's existing Beulah Mine. See Attachment 1 for the relative locations of these facilities and their operating activities.

Construction activities at the mine, primarily with respect to the dragline, are scheduled to begin in 2014. Commercial delivery of lignite is scheduled to begin by May 2016 under a lignite sales agreement with the Coyote Station owners. The 25-year sales agreement provides for lignite delivery through 2040 with opportunity for extension. The sales agreement is described further below as relevant to the stationary source regulatory criteria.

Separate Stationary Source Determination

Under Federal and North Dakota PSD regulations, a "stationary source" is defined as "any building, structure, facility or installation which emits or may emit a regulated NSR pollutant."[3] "Building, structure, facility or installation" is defined as "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) . . .."[4] If the pollutant-emitting activities fail to satisfy any one of the three criteria, they are considered separate stationary sources and their emissions cannot be aggregated for PSD applicability purposes.

Common Control

Common control is not explicitly defined by NDDH or EPA; however, the most common and clearest understanding of the common control criterion is by common ownership, consistent with the intent of the PSD rules. As described in this section, CCMC and the owners of Coyote Station are completely separate, and there is no shared equity position between the two ownership groups.

The EPA has made a determination in a situation very similar to the one here. In the late 1990's, the Mississippi Lignite Mining Company, which is owned by the same parent company as CCMC, constructed a new lignite mine (Red Hills Mine) to be the exclusive fuel provider to an adjacent power plant separately owned and operated by Choctaw Generation, LLP. The lignite from Red Hills Mine was being provided under a 30-year lignite sales agreement. The EPA acknowledged that the mine and power plant are separate sources for PSD applicability purposes because of separate ownership and separate

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[3] 40 CFR § 52.21(b)(5).

[4] 40 CFR § 52.21(b)(6).

control.[5] A copy of the EPA's letter is Attachment 2. The EPA deemed the mine's pollutant-emitting activities to be "secondary emissions" to those of the power plant. Secondary emissions are defined as:

> *...emissions which would occur as a result of the construction or operation of a major stationary source or major modification, but do not come from the major stationary source or major modification itself. Secondary emissions include emissions from any offsite support facility which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification.*[6]

Secondary emissions do not count in determining the potential to emit of a stationary source for applicability purposes, but rather are considered in a source impact analysis for proposed sources or modifications that are subject to PSD.[7]

In addition to common ownership, we understand that the EPA has identified a number of additional factors that it considers relevant to the common control issue. These factors emanate from EPA guidance memoranda and court cases rather than in regulations subject to public notice and comment. As the primacy agency, the NDDH has the discretion to apply them in a given situation. Three key EPA memoranda are normally referenced for these factors: a September 18, 1995 Response from William A. Spratlin to Iowa Department of Natural Resources; an August 2, 1996 Memorandum from John S. Seitz; and, an October 1, 1999 Response from Richard Long to Colorado Department of Public Health Environment. In these memoranda, the EPA has determined that common control relationships can possibly be established through both direct control (e.g., ownership or subsidiaries) or indirect control (e.g., contractual or leasing agreements) depending on the support/dependency relationships (i.e, one would not exist "but for" the other).

Below we have summarized these functional factors generally used to determine common control, along with a description of the relationship between CCMC and Coyote Station.

1. *Common control can be established through ownership (i.e., same parent company or a subsidiary of the parent company).* There is no common ownership or equity position between any of these companies with respect to CCMC or Coyote Station. CCMC is a wholly-owned subsidiary of The North American Coal Corporation, which is a wholly-owned subsidiary of NACCO Industries, Inc., a publicly-traded company in Cleveland, Ohio. Coyote Station is owned, as tenants in common, by Otter Tail Power Company, Montana-Dakota Utilities Co., Northern Municipal Power Agency, and NorthWestern Energy. None of those entities maintains any ownership in CCMC or The North American Coal Corporation. To the extent any of the power plant owners own any stock in NACCO, such ownership, if any, is nominal, and does not afford them any right of control over NACCO.

2. *Common control can be established if an entity such as a corporation has decision-making authority over the operations of a second entity through a contractual agreement or a voting interest.* The CCM and Coyote Station are operated by separate companies that do not have common decision making oversight. The Coyote Station owners do not have decision making authority over CCMC,

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[5] Letter from Stanley Krivo of US EPA Region 4 to Laura Burrell of the Mississippi Department of Environmental Quality.

[6] 40 CFR § 52.21(b)(18).

[7] 40 CFR § 52.21(b)(4) and § 52.21(k).

nor does CCMC have any authority over the plant or its operations. Operational decisions, at the mine and the power plant, are independently made. CCMC will sell lignite to the Coyote Station owners pursuant to a Lignite Sales Agreement (the Agreement). The Agreement anticipates a certain amount of coordination between the parties. For example, each year, the Coyote Station owners are supposed to notify CCMC of the estimated amount of lignite they expect to use in the upcoming year on a monthly basis. The estimates will enable CCMC to carry out its operations accordingly. Aside from that, all engineering, land, geological, operational, administrative, environmental permitting and compliance, managerial, and other work required to supply lignite for use at Coyote Station is the exclusive responsibility of CCMC. Reclamation work is also CCMC's exclusive responsibility. The Agreement further provides that CCMC is an independent vendor (as opposed to an "agent" or "servant"), and that the Agreement shall not "be construed to constitute or create a joint venture, trust, mining partnership, commercial relationship, fiduciary relationship or other relationship between" the parties. Given that the Agreement is "cost-plus," meaning that the Coyote Station owners will pay certain CCMC operating costs, the owners have the right to approve certain significant capital expenditures. They do not, however, exercise authority over the day-to-day mining operations: they don't hire or fire mine employees, make crew assignments, or establish work shifts. They do not schedule equipment. Nor do they direct pollution control activities at the mine-site, which, by the nature of the operation, are significantly different from pollution control activities at the power plant.

3. *Common control can be established if there is a contract-for-service relationship between the two entities or if a support/dependency relationship ("but for") exists between the two entities such that a common control relationship exists.* The Agreement is not exclusive in perpetuity, and during its existence the Agreement allows the Coyote Station owners to import and use fuels from other resources in certain situations. The Agreement also allows CCMC to mine and sell lignite to third parties so long as doing so will not impair CCMC's ability to meet its supply obligations to the Coyote Station owners under the Agreement. Also, the Coyote Station owners can terminate the Agreement under certain circumstances. The lack of a "but for" relationship is evidenced by the current situation at Coyote Station. Specifically, Dakota Westmoreland's Beulah Mine currently provides the vast majority of its mined lignite to Coyote Station. The mine, however, was opened in 1963 to serve other customers, and for the better part of eighteen years it operated without Coyote Station.[8] When Coyote Station came on line in 1981, the mine expanded its operations to meet the plant's needs.[9] Not only was the mine a viable operating entity before the plant existed, Dakota Westmoreland apparently intends to continue operating after its lignite sales agreement expires.[10] In the same vein, the CCM intends to provide most of its lignite to Coyote Station, but under the lignite sales agreement with the Coyote Station owners the mine is able to serve other lignite users as well.

The aforementioned three factors are referenced in EPA's 1999 memorandum where they cite use of the Securities and Exchange Commission (SEC) definition of control as guidance. The SEC definition states:

> Control means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person whether through the ownership of voting shares, contract or otherwise (17 CFR 240.12b-2).

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[8] http://www.westmoreland.com/beulah, accessed February 1, 2013.

[9] https://www.lignite.com/?id=71, accessed February 1, 2013.

[10] Bismarck Tribune article, November 4, 2012. "Bill Weaver, mine manager, said his company is evaluating other options after 2016 and thinks the Heskett contract is enough to keep the mine open."

A 2009 court case, *Winnebago Industries v. Iowa DNR*, reversed an Iowa Department of Natural Resources finding that co-located vehicle manufacturer and surface coating plants were a single stationary source based upon the court's emphasis on the SEC definition as compared to other broader questions that EPA has used for determining common control. In this decision, the court focused on the power of a company to direct or cause the direction of management and policies, as opposed to economic influences. As applied to this situation, the Coyote Station owners do not have specific power to direct the management of CCMC.

Other broader factors the EPA and state agencies with primacy have used in source determinations, and their applicability here, include the following.

- *What is the dependency of one facility on the other? Can a facility continue to operate if the other shuts down? If one shuts down, what are the limitations on the other to pursue outside business interests?* Coyote Station will receive a regular dependable supply of lignite from CCMC's mine. If CCMC is unable to carry out its obligations under the Agreement, CCMC is responsible for securing replacement fuel. Also, if the mine were to shut-down completely, the plant could still operate, as evidenced by the fact that it has been in operation since 1981, well before CCMC was formed. Additionally, CCMC's existence is not dependent on the Coyote Station plant. If supplies to the plant curtailed for any reason, CCMC could and would pursue lignite sales, or continue to sell lignite, to third parties. Lignite sales to third parties are specifically contemplated in the Agreement. Also, as noted above, the Dakota Westmoreland Beulah Mine that has supplied lignite to the Coyote Station was in operation 18 years before the power plant began operating, and apparently Dakota Westmoreland is considering plans to keep the mine open after its sales agreement expires in 2016.

- *Does one operation support the operation of the other? Do the facilities share intermediates, products, byproducts, or other manufacturing equipment?* While CCMC will provide lignite to Coyote Station, there will not be any sharing of equipment, facilities, products, or byproducts. Additionally, there shall be a clear delineation of when title to the lignite is transferred to Coyote Station for its handling and use under its existing air permit.

- *What are the contractual arrangements for providing goods and services? Can the new source purchase raw materials from and sell products or byproducts to other customers?* CCMC will supply lignite to Coyote Station under the Agreement. The Agreement allows CCMC to sell lignite to third parties if CCMC demonstrates that doing so will not impair CCMC's ability to meet its supply obligation. Similarly, the Agreement allows the Coyote Station owners to buy lignite from CCMC and then turn-around and sell it at a profit to third parties.

- *What are the financial arrangements between the two entities?* CCMC will invoice the Coyote Station owners on a monthly basis for its actual costs, plus a profit margin.

- *Do the facilities share equipment, other property, or pollution control equipment?* CCMC will own all of its own equipment, including pollution control equipment, and all other property. CCMC and the Coyote Station owners do not envision sharing any equipment.

- *What does the contract specify with regard to the pollution control responsibilities of the contractee?* The parties each have control over their own pollution control responsibilities. There is no overlap between the mine and the power plant. Although each has air and water permits, the permits are different in nature and are issued under separate categories for coal mining and power production.

- *Who accepts the responsibility for compliance with air quality control requirements? What about for violations of the requirements?* CCMC will be responsible for the operation of the proposed mine and is responsible for compliance with all air quality pollution control requirements. Legal liability for violations at the mine will fall exclusively on CCMC; the Coyote Station owners agreed to reimburse CCMC for financial penalties. CCMC has no responsibility for air quality control requirements at the plant, nor does it have any legal liability for any violations. The Coyote Station owners are responsible for air quality control requirements, and liability for such violations is between the owners.

- *Can the managing entity of one facility make decisions that affect pollution control at the other facility?* CCMC and Coyote Station would be operated by separate companies that do not make decisions regarding pollution control at each other's facilities.

- *Do the facilities share common workforces, plant managers, security forces, corporate executive officers, or board executives?* CCMC and Coyote Station do not share common workforces, plant managers, security forces, corporate executives, or board executives.

- *Do the facilities share common payroll activities, employee benefits, health plans, retirement funds, insurance coverage, or other administrative functions?* CCMC and Coyote Station do not share common payroll activities, employee benefits, health plans, retirement funds, insurance coverage, or other administrative functions.

Based on the information provided, CCMC and the Coyote Station owners are under separate control.

Industrial Grouping

The PSD and Title V programs provide that sources must belong to the same industrial grouping (two-digit SIC code) to be considered the same stationary source. This industrial grouping criterion was added as a third criterion in the 1980 PSD rule amendments[11] as a result of a Court of Appeals decision in *Alabama Power v. Costle,* in which the court rejected the definition of "source" in the 1978 PSD regulations.[12] An excerpt from the regulatory preamble that sets forth this criterion is provided below for context on applying the criterion to CCMC and Coyote Station.

> *After considering the comments of those who objected to the use of proximity and control only, EPA has decided to adopt for PSD purposes a definition of "building, structure, facility, and installation" that is different from the one it proposed in September. The final definition provides that those component terms each denote "all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same 'Major Group' (i.e., which have the same two-digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively)."*
>
> *In EPA's view, the December opinion of the court in Alabama Power sets the following boundaries on the definition for PSD purposes of the component terms of "source": (1) it must*

[11] 45 FR 52676-52748, August 7, 1980.

[12] *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979).

> *carry out reasonably the purposes of PSD; (2) it must approximate a common sense notion of "plant"; and (3) it must avoid aggregating pollutant-emitting activities that as a group would not fit within the ordinary meaning of "building," "structure," "facility," or "installation."*
>
> *The comments on the proposed definition of "source" have persuaded EPA that the definition would fail to approximate a common sense notion of "plant," since in a significant number of cases it would group activities that ordinarily would be considered as separate. For instance, a uranium mill and an oil field would ordinarily be regarded as separate entities, yet the proposed definition would treat them as one.*
>
> *In formulating a new definition of "source," EPA accepted the suggestion of one commenter that the Agency use a standard industrial classification code for distinguishing between sets of activities on the basis of their functional interrelationships. While EPA sought to distinguish between activities on that basis, it also sought to maximize the predictability of aggregating activities and to minimize the difficulty of administering the definition. To have merely added function to the proposed definition as another abstract factor would have reduced the predictability of aggregating activities under that definition dramatically, since any assessment of functional interrelationships would be highly subjective. To have merely added function would also have made administration of the definition substantially more difficult, since any attempt to assess those interrelationships would have embroiled the Agency in numerous, fine-grained analyses. A classification code, by contrast, offers objectivity and relative simplicity.* (underlined for emphasis)

On the basis of using the two-digit classification code, CCM is a coal mine in SIC major group 12. Coyote Station generates electricity, which is in SIC major group 49. The major industrial groupings are different between CCM and Coyote Station.

In the same rule preamble, the EPA prescribed that the two-digit SIC code grouping should be assigned to the primary activity of the source. Pollutant-emitting activities that support the primary activity are labeled by the EPA as a "support facility." However, as stated by the EPA in the rule preamble below, CCM as a surface coal mine and Coyote Station as an electrical generator have separate primary activities. Whether the coal mine serves one customer or multiple customers is irrelevant to the industrial grouping criterion.

> *Each source is to be classified according to its primary activity, which is determined by its principal product or group of products produced or distributed, or services rendered. Thus, one source classification encompasses both primary and support facilities, even when the latter includes units with a different two-digit SIC code. Support facilities are typically those which convey, store, or otherwise assist in the production of the principal product. Where a single unit is used to support two otherwise distinct sets of activities, the unit is to be included within the source which relies most heavily on its support. For example, a boiler might be used to generate process steam for both a commonly controlled and located kraft pulp mill and plywood manufacturing plant. If the yearly boiler output is used primarily by the pulp mill, then the total emissions of the boiler should be attributed to the mill.*
>
> *In adopting the new definition of "source," EPA rejected the requests of those commenters who thought that the proposed definition would not be inclusive enough. As noted above, they urged that EPA formulate a definition that looked only to proximity and function. But such a definition by looking to function would unnecessarily increase uncertainty and drain the Agency's*

> *resources. In addition, such a definition would present groupings, such as the example the commenters gave, that would severely strain the boundaries of even the most elastic of the four terms, "building," "structure," "facility," and "installation."*
>
> *EPA is unable to say precisely at this point how far apart activities must be in order to be treated separately. The Agency can answer that question only through case-by-case determinations. One commenter asked, however, whether EPA would treat a surface coal mine and an electrical generator separated by 20 miles and linked by a railroad as one "source," if the mine, the generator, and the railroad were all under common control. EPA confirms that it would not. First, the mine and the generator would be too far apart. Second, each would fall into a different two-digit SIC category.* (underlined for emphasis)

The view that a coal mine and an electrical generating station are individual primary activities because these source categories are separate types of businesses, regardless of how much of the coal is provided to a given consumer, is further affirmed by the EPA in a new source applicability example in written guidance, excerpted below.[13]

> *In this example the proposed project is a new coal-fired electric plant. The plant will have two 600-MW lignite-fired boilers. The proposed location is near a separately-owned surface lignite mine, which will supply the fuel requirements of the power plant, and will therefore, have to increase its mining capacity with new equipment. The lignite coal will be mined and then transported to the power plant to be crushed, screened, stored, pulverized and fed to the boilers. The power plant has informed the lignite coal mine that the coal will not have to be cleaned, so the mine will not expand its coal cleaning capacity.*
>
> . . .
>
> *The first step is to determine what constitutes the source (or sources). A source is defined as all pollutant-emitting activities associated with the same industrial grouping, located on contiguous or adjacent sites, and under common control or ownership. Industrial groupings are generally defined by two-digit SIC codes. The power plant is classified as SIC major group 49; the nearby mine is SIC major group 12. They are neither under the same SIC major group number nor have the same owners, so they constitute separate sources.*

The EPA occasionally has suggested a "but for" test to be used to determine if a support or dependency relationship exists between two entities, thus creating questions about the primary activity of a source or group of sources. Not only is that inconsistent with the EPA materials discussed above, but perhaps more importantly the "but for" test is nowhere to be found in the text of the regulation, which simply states that "[p]ollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same Major Group . . . as described in the Standard Industrial Classification Manual." Because the implementing regulation is so clear, and because the regulation does not say anything about a "but for" test, it is unnecessary to look beyond the "industrial grouping" language in the regulation, or to effectively read into it a "but for" test or any other test that purports to analyze the extent to which the mine supports Coyote Station. In *Christensen v. Harris County,* for example, the Supreme Court ruled that a federal agency is bound to apply its unambiguous regulation as written, and that it may not, under the "guise of interpretation," supplement that regulation with other factors or additional requirements because doing so would effectively allow the agency "to create *de facto* a new regulation" without going through the notice

[13] US EPA, "Draft NSR Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting," October 1990.

and comment procedure.[14] *Color Communications, Inc. v. Illinois Pollution Control Board* is also instructive. In that case, although the facilities in question had different SIC codes, the Pollution Control Board had ruled they were a single source since one facility supported the other. On appeal, the court reversed that finding, stating:

> *In this case the plain language of the statute, as set forth above, clearly requires that if several stationary sources have the same two-digit SIC code, they must be considered to belong to a single major industrial grouping. Accordingly, an industrial grouping is defined by SIC codes. A plain reading of this statute is that if several stationary sources do not have the same two-digit SIC code, they do not belong to the same industrial grouping.*
>
> *Where a statute is clear and unambiguous, as this one is, a court is not at liberty to depart from its plain language and meaning by reading into it limitations or conditions that the legislature did not express. . . By relying on the support-facility concept, the Board improperly looked beyond the unambiguous language of the statute to determine whether the two plants belonged to a single industrial grouping. Accordingly, the Board erred in concluding the plants constituted a "single source". . .*[15]

The bottom line is that the CCM and Coyote Station have separate industrial groupings and therefore constitute separate sources.[16]

Notwithstanding that such a relationship evaluation is functional in nature and was thus rejected already by EPA as a criterion in the 1980 PSD rulemaking, CCMC would satisfy such a test, as evidenced by the very situation in place at Coyote Station. As previously pointed out, Dakota Westmoreland's Beulah Mine currently provides the vast majority of its mined lignite to Coyote Station, and in fact has been doing so since 1981. The mine, however, was opened in 1963 and for eighteen years served other customers[17] until its operations expanded substantially to satisfy Coyote Station, which came on-line in October 1981.[18] Moreover, Dakota Westmoreland apparently intends to continue operating after its lignite sales agreement expires.[19] In the same vein, CCM intends to provide most of its lignite to Coyote Station, but under its lignite sales agreement the mine is able to serve other lignite users as well.

<u>Contiguous or Adjacent Properties</u>
CCMC's mining operations constitute the "pollutant-emitting activities" stated in the definition above. The mining operations proper are located on property owned or maintained through leases and, at present, are over three miles from, and not contiguous or adjacent to, Coyote Station's property, as illustrated in Attachment 1. CCMC is currently evaluating different options for delivering the lignite from the mining operations proper to the Coyote Station. The lignite will be hauled by truck, conveyor, or similar haulage

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[14] 529 U.S. 576, 588 (2000).

[15] 680 N.E. 2d 516, 533 (Ill. Ct. App. 1997), *petition for leave to appeal denied,* 686 N.E.2d 1159 (Ill. 1997).

[16] Also, applying the "but for" test in the context of the SIC code criterion is unnecessary since, as noted already, the same test arises in connection with the common control criterion.

[17] http://www.westmoreland.com/beulah, accessed February 1, 2013.

[18] https://www.lignite.com/?id=71, accessed February 1, 2013.

[19] Please see footnote 10, page 4.

system around the Dakota Westmoreland property that currently separates the CCM from the Coyote Station. The lignite will likely will be conveyed by belt conveyor across the property/permit boundary between the CCM and the Coyote Station with transfer of ownership of the lignite occurring during the conveyance.

As you probably know, the "contiguous or adjacent" criterion recently was litigated in the United States Court of Appeals for the Sixth Circuit.[20] In its August 2012 decision, the court held that facilities are "contiguous or adjacent" when they physically adjoin one another. Significantly, the court rejected the EPA's interpretation, which had emphasized "the functional interrelationship" of the facilities in question. *Summit Petroleum*, 690 F.3d at 742 ("The EPA makes an impermissible and illogical stretch when it states that one must ask the *purpose* for which two activities exist in order to consider whether they are adjacent to one another").[21]

Furthermore, consideration of facilities functional interrelationship in conjunction with physical adjacency is not warranted, since there is already a separate factor, industrial grouping, that is used to determine if multiple activities are engaged in the same type of business. Indeed, in the 1980 amendments to the PSD rules that added the industrial grouping criterion to the stationary source definition, EPA specifically had considered, requested comment on, and subsequently rejected a test of whether activities are sufficiently functionally related because it would be "would be highly subjective" and would make "administration of the definition substantially more difficult.[22] Instead, the EPA elected to incorporate the new industrial grouping criterion, thereby allowing the factor of physical adjacency to be evaluated more clearly.

Although the EPA could have attempted to appeal the Sixth Circuit's decision in *Summit Petroleum* to the United States Supreme Court, it did not do so. Instead, the EPA issued internal correspondence that the determination of contiguous or adjacent properties in the Federal regulations will be applied differently between the States in the Sixth Circuit (Michigan, Ohio, Tennessee, Kentucky) and all other States, inasmuch as EPA has direct jurisdiction for areas in these States.[23] The *Summit Petroleum* case involved EPA's implementation of the PSD program on an Indian reservation in Michigan. The EPA does not operate the PSD program in North Dakota except for sources proposing to construct on Indian reservations. Instead, the NDDH operates its own EPA-approved PSD program under North Dakota Administrative Code Chapter 33-15-15 in all areas of North Dakota outside of Indian reservations.[24] CCMC is not located on an Indian reservation and is therefore subject to the purview of NDDH's permitting authority. Based on a review of case-by-case source aggregation decisions by the NDDH, it

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[20] *Summit Petroleum Corp. v. United States EPA*, 690 F.3d 733 (6^{th} Cir. 2012).

[21] The Court also noted that the EPA's interpretation was not entitled to any deference since "contiguous or adjacent" is unambiguous.

[22] 45 FR 52694-52695, August 7, 1980.

[23] December 21, 2012, US EPA Memorandum from Stephen D. Page to Regional Air Directors, "Applicability of the Summit Decision to EPA Title V and NSR Source Determinations."

[24] 40 CFR § 52.1829(a).

has consistently relied on physical proximity within the ordinary (i.e., physical and geographical) meaning of "adjacent."[25]

Conclusion

The proposed Coyote Creek Mine has a separate major industrial grouping and is not under common control with the existing Coyote Station power plant. Accordingly, based on the application above of the legal criteria for determining the applicability of PSD, Section 112 air toxics, and Title V, we believe that the Coyote Creek Mine should be considered a separate stationary source from the existing permitted Coyote Station. Upon the NDDH's review and approval of this request, CCMC will complete the permit applicability analysis and submit an air quality permit to construct application to the NDDH.

Please contact me at 701-873-7227 or Joel Trinkle with Barr Engineering Company at 952-832-2870 if you would like any additional information or have any questions. We look forward to hearing from you regarding this project.

Sincerely,

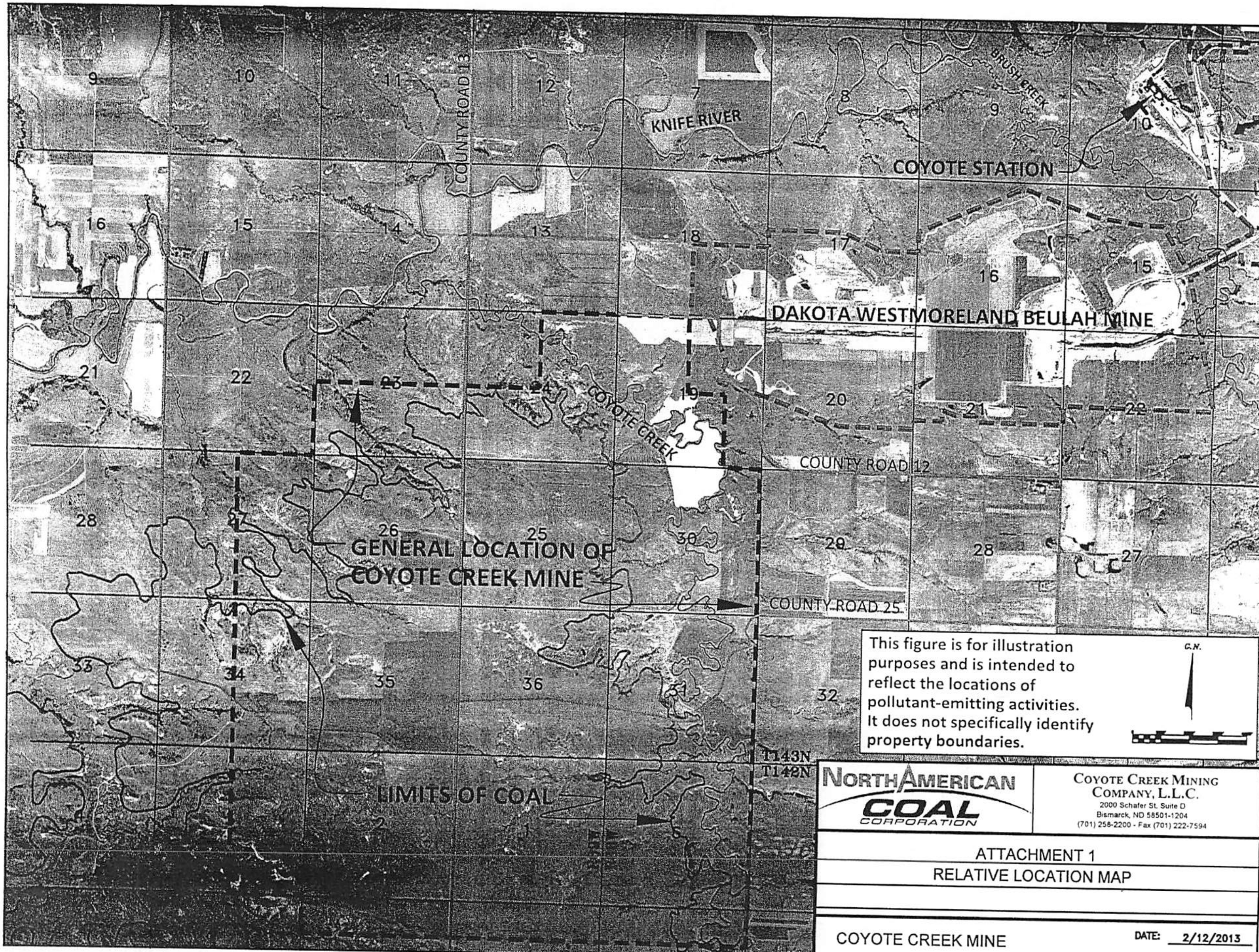
COYOTE CREEK MINING COMPANY, L.L.C.

Donn R. Steffen
Environmental Manager

cc: Justin Burggraff
Joel Trinkle, Barr Engineering Company

Attachment 1 – Map of the CCM/Coyote Station Site
Attachment 2 – EPA Letter to MDEQ

[25] Case in point, see the NDDH determinations: 1) May 12, 2005, regarding Coal Creek Station and Blue Flint Ethanol, 2) September 7, 2006, regarding Spiritwood Industrial Park, 3) October 14, 2011, regarding Enbridge Stations. All three determinations rely on the physical proximity of the separately owned properties for this criterion.



This figure is for illustration purposes and is intended to reflect the locations of pollutant-emitting activities. It does not specifically identify property boundaries.

NORTHAMERICAN COAL CORPORATION

COYOTE CREEK MINING COMPANY, L.L.C.
2000 Schafer St. Suite D
Bismarck, ND 58501-1204
(701) 258-2200 - Fax (701) 222-7594

ATTACHMENT 1

RELATIVE LOCATION MAP

COYOTE CREEK MINE

DATE: 2/12/2013

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW
ATLANTA, GEORGIA 30303-8909

JAN 20 1998

4APT-ARB

Ms. Laura L. Burrell
State of Mississippi
Department of Environmental Quality
Office of Pollution Control
P.O. Box 10385
Jackson, MS 39289-0385

Re: Secondary Emissions For PSD Air Quality Assessments
Choctaw Generating, Inc., Red Hills Generating Facility
Choctaw County, Mississippi

Dear Ms. Burrell:

This letter is in response to your request for documentation of our discussions concerning the modeling procedure to address the air quality impacts of secondary emissions for the proposed Red Hills Generating Facility (RHGF). Emissions from the RHGF will be greater than the Prevention of Significant Deterioration (PSD) major source emission level - the reason for the PSD application for the RHGF power plant. To provide fuel for the RHGF, a company not related to Choctaw Generating, Inc. will develop a lignite mine on adjacent property. Although no PSD permit is required for the mine's operation because its emissions are less than the PSD major limits, the mine's emissions are "secondary emissions" for the power plant and must be included in the impact assessment for RHGF (reference: New Source Review Workshop Manual, 1990, Section II.B.4).

Of concern to the MS Department of Environmental Quality (MSDEQ) in the air quality impact assessment is the location of receptors for the analysis of the mine's impact. PSD computer impact modeling of the power plant's emissions are performed at receptors located on non-power plant property (i.e., power plant ambient air defined as air not over land owned or controlled by the plant with physical barriers precluding public access) which includes the mine property. MSDEQ's question in modeling the secondary mine emissions is whether the power plant "ambient air" is used for the mine's impact analysis (i.e., impact analysis of mine emissions at receptors located on the mine's property) or does the mine have its own ambient air defined by the mine's property boundary?

To address the ambient air issue for secondary emissions, I have contracted both USEPA Regional 4 and OAQPS modelers as well as reviewed available USEPA documented guidance. Although no specific guidance document was available on this issue, all Regional and OAQPS individuals contacted agreed that PSD air quality impacts are not modeled on the property owned and controlled by the owner of the emission source. Therefore, secondary emissions from a separately owned and controlled mine should be modeled in ambient air for the mine. The modeling receptor grid for the mine should include properties outside the mine's property boundary which includes the power plant property.

I hope this letter satisfies your request for documentation of our discussions concerning ambient air impact modeling of secondary emissions for the Red Hills Generating Facility. Please let me know if you have further questions on this subject.

Sincerely,

Stanley J. Krivo

Stanley J. Krivo, CCM, QEP
Environmental Scientist
Preconstruction/Hazardous Air
Pollution Section
Air & Radiation Technology
Branch

April 30, 2018 EPA Letter

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON D.C. 20460

April 30, 2018

AIR AND RADIATION

The Honorable Patrick McDonnell
Secretary of the Pennsylvania Department
 of Environmental Protection
Rachel Carson Office Building
Post Box 2063
Harrisburg, Pennsylvania 17105

Dear Mr. McDonnell:

On February 14, 2018, the Pennsylvania Department of Environmental Protection (PADEP) requested that the U.S. Environmental Protection Agency review a document submitted on behalf of Meadowbrook Energy LLC (Meadowbrook) concerning whether emissions from a biogas processing facility under development by Meadowbrook should be aggregated with an existing landfill owned by Keystone Sanitary Landfill, Inc. (KSL) for Clean Air Act (CAA) permitting purposes.

EPA understands this request to relate to the question of whether these two entities should be considered part of the same "major source" under the operating permit program under title V of the CAA, and/or part of the same "stationary source" for the New Source Review (NSR) pre-construction permit programs under title I of the CAA.[1] EPA commonly refers to these types of questions as "source determinations." Under the federal rules governing these permitting programs, entities may be considered part of the same "stationary source" or "major source"[2] if they (1) belong to the same industrial grouping; (2) are located on one or more contiguous or adjacent properties; and (3) are under the control of the same person (or persons under common control).[3] Meadowbrook's analysis, as supplemented by additional analysis dated March 16, 2018, primarily asserts that the Meadowbrook and KSL facilities are not under "common control."

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[1] Although it appears that Meadowbrook's analysis only directly implicates title V permitting, the discussion in this letter and the Attachment is relevant to NSR permitting actions as well. In the NSR regulations, the definitions of "stationary source" use the term "building, structure, facility, or installation," which is separately defined.

[2] References to "major source" in this letter or Attachment are intended to refer only to the portions of the title V definitions of "major source" that relate to which activities should be considered part of the same "major source."

[3] *See* 42 U.S.C. § 7661(2) (title V statutory definition); 40 C.F.R. §§ 70.2 & 71.2 (title V regulations); 40 C.F.R. §§ 52.21(b)(5) & (6), 51.165(a)(1)(i) & (ii), and 51.166(b)(5) & (6) (NSR regulations). PADEP's permitting regulations either incorporate EPA's prevention of significant deterioration (PSD) regulations or contain similar provisions. *See, e.g.*, 25 Pa. Code 127.83 (PSD regulations incorporating EPA's regulations in 40 C.F.R. § 52.21);

As described more fully in the Attachment below, EPA has long recognized that common control determinations should be made on a case-by-case basis. In making such determinations, and in offering its views to other permitting authorities, EPA has previously interpreted the term "common control" in a manner that may support viewing the Meadowbrook and KSL facilities as a single "stationary source" or "major source" by virtue of the support or dependency relationships between the two entities that might be viewed as providing each entity with some degree of influence over the operations of the other.

However, the potential for that interpretation to produce inconsistent and impractical outcomes in this and other cases has caused EPA to re-evaluate and revise its interpretation of the term "common control" in the title V and NSR regulations. For the reasons discussed further in the Attachment, the agency believes clarity and consistency can be restored to source determinations if the assessment of "control" for title V and NSR permitting purposes focuses on the power or authority of one entity to dictate decisions of the other that could affect the applicability of, or compliance with, relevant air pollution regulatory requirements. Under this revised interpretation, EPA agrees with Meadowbrook that PADEP may conclude that the Meadowbrook and KSL facilities are not under common control and thus not a single "stationary source" or "major source" for title V or NSR purposes. However, given that Pennsylvania's title V and NSR programs have been approved by EPA, PADEP has primary responsibility to make source determinations involving the Meadowbrook and/or KSL facilities based on its EPA-approved rules. EPA believes that the following Attachment, in explaining EPA's revised interpretation and other factors that EPA recommends considering when determining if there is "common control," should be helpful to PADEP as it makes its final permitting decision with respect to Meadowbrook.

If you have any additional questions, please contact Anna Marie Wood in the Office of Air Quality Planning and Standards at (919) 541-3604 or *wood.anna@epa.gov*.

Sincerely,

William L. Wehrum
Assistant Administrator

Attachment

cc: Krishnan Ramamurthy, Director of Air Quality, PADEP
Mark Wejkszner, Air Quality Program Manager, PADEP, Region 2

---

see also 25 Pa. Code 121.1 (general air quality definition of "facility"); 25 Pa. Code 127.204(a) (nonattainment NSR regulations discussing aggregation).

Letter: William L. Wehrum, Assistant Administrator, Office of Air and Radiation, U.S. Environmental Protection Agency, to the Honorable Patrick McDonnell, Secretary, Pennsylvania Department of Environmental Protection (April 30, 2018)

Attachment

I. Meadowbrook and KSL Background

Meadowbrook Energy LLC (Meadowbrook) has indicated that it plans to construct a biogas processing facility that will convert landfill gas (LFG) and other potential biogas feedstocks into pipeline-quality natural gas for injection into the interstate natural gas pipeline system, to be used as a transportation fuel. Meadowbrook has entered into an agreement with Keystone Sanitary Landfill, Inc. (KSL),[4] whereby KSL will deliver LFG to Meadowbrook via a pipeline running between the two facilities. This pipeline will be owned by KSL up to a demarcation point, at which point the remainder of the pipeline will be separately owned by Meadowbrook.

Meadowbrook explains that KSL controls its own landfill gas collection activities and delivers untreated landfill gas to the demarcation point. After the demarcation point, Meadowbrook conducts all processing of the gas necessary to create the renewable natural gas product that it injects into the pipeline for market sale. Meadowbrook represents that the two entities have no cross-ownership or direct control over operations at the other facility. In other words, each entity has no ability to control, operate, close, or restrict the use of the other's facility.[5] Meadowbrook characterizes the relationship between the two facilities as arms-length arrangements between independent commercial entities. Meadowbrook therefore believes that Meadowbrook and KSL should not be considered under "common control," and thus their facilities should not be considered a single source.

More specifically, Meadowbrook maintains that KSL is not dependent on Meadowbrook for compliance with any portion of the requirements associated with the control of the emission of KSL's LFG. Meadowbrook indicates that KSL will retain full responsibility for compliance with all air pollutant control obligations (*e.g.*, New Source Performance Standards (NSPS) Subpart WWW requirements for LFG) until the LFG is delivered to the demarcation point (*i.e.*, until the gas is delivered to Meadowbrook). If Meadowbrook cannot accept LFG, shutoff valves in the pipeline between LFG and Meadowbrook will redirect all of the LFG to KSL's flares for

[4] Meadowbrook indicates that this agreement is subject to future revisions. The information provided to PADEP by Meadowbrook in its initial draft analysis and its updated March 16, 2018, analysis apparently reflects the mutual understandings of Meadowbrook and KSL as of the date of these analyses.

[5] Meadowbrook acknowledges that Meadowbrook will provide either labor (likely through a third-party) or financing associated with modifying or optimizing KSL's landfill gas collection system in order to set up the pipeline between Meadowbrook and KSL. However, Meadowbrook claims that KSL would direct any Meadowbrook personnel, or third-party personnel provided by Meadowbrook, in these efforts, and that Meadowbrook would not have any rights to direct or control the operation of the LFG collection system. Additionally, Meadowbrook indicates that it is currently considering the possibility of interconnecting with KSL's leachate, condensate, and wastewater treatment systems to dispose of certain Meadowbrook products at market prices.

destruction. KSL is required to construct and maintain sufficient flare capacity to destroy 100% of KSL's LFG, and Meadowbrook states this flare capacity exists and is currently permitted.[6] Thus, Meadowbrook concludes that even the closure of the Meadowbrook facility would not have environmental consequences to KSL's operations, nor would it affect the ability of KSL to comply with environmental regulatory requirements related to its LFG.

Meadowbrook also maintains that it is not dependent on KSL for its supply of LFG. Meadowbrook acknowledges that it has the right to purchase, and expects to purchase, all of the LFG produced by KSL to serve as a feedstock, and that Meadowbrook will rely on KSL for its first supply of LFG to produce a natural gas product for commerce. However, Meadowbrook represents that it is only required to accept as much LFG as Meadowbrook can process. Meadowbrook also indicates that its processing capacity exceeds KSL's LFG production, and that Meadowbrook is actively seeking additional suppliers of LFG and other types of biogas in order to serve as a regional refining and processing facility. Moreover, Meadowbrook claims that even if KSL were to shut down, and even if this resulted in the eventual shutdown of Meadowbrook itself, this shutdown would have no environmental consequences. Based on this, Meadowbrook asserts that it retains sole responsibility for environmental regulatory requirements (related to LFG, or otherwise) arising after the demarcation point, and that its air emissions are in no way influenced by KSL's landfill operations.

Meadowbrook emphasizes the separate compliance responsibilities of each entity, and the fact that neither entity would be able to operate the other's facility to ensure that the other's facility complies with relevant environmental requirements. First, Meadowbrook briefly discusses its own practical difficulties in having to assure its customers or potential suppliers that it is not liable for KSL's operations. Additionally, Meadowbrook highlights practical difficulties with aggregating the two entities for permitting purposes: specifically, difficulties with including Meadowbrook's operations within KSL's existing title V permit for title V compliance certification purposes. Meadowbrook notes that, if Meadowbrook's operations were incorporated into KSL's existing title V permit, KSL's responsible official would be required to certify the accuracy of such a permit modification application with respect to Meadowbrook's operations, as well as certify Meadowbrook's compliance with relevant requirements. *See* 25 Pa. Code §§ 127.402(d), 127.205(2).[7] Meadowbrook argues that the responsible official at KSL would have no way to accurately certify permit applications pertaining to Meadowbrook's facility, nor could KSL's responsible official certify Meadowbrook's compliance, because KSL has no information about or access to proprietary equipment or operations at the Meadowbrook facility. Thus, Meadowbrook argues that it would be unrealistic to expect that KSL could effectively discharge KSL's title V compliance certification requirements (with the potential for criminal liability) if the two sources were aggregated.

[6] Meadowbrook acknowledges that KSL's title V permit will likely be modified to add an option to divert LFG to Meadowbrook, but claims that this will not affect KSL's ability to maintain title V compliance (presumably, compliance with subpart WWW requirements) through use of its existing LFG collection system and flares.

[7] Meadowbrook also references KSL's obligation to certify ongoing compliance and suggests that KSL could be held liable for Meadowbrook's operations. *See* 25 Pa. Code §§ 127.511(c)(1), 127.411(a)(1).

II. Background on EPA Interpretations of Common Control

When determining which pollutant-emitting activities should be considered part of the same "major source" under the title V operating permit program, and/or part of the same "stationary source" under the New Source Review (NSR) program, permitting authorities should assess the three factors contained in EPA's title V and NSR regulations—same industrial grouping, location on contiguous or adjacent property, and common control—on a case-by-case basis. In the title V regulations, these criteria are reflected in the definition of "major source." 40 C.F.R. §§ 70.2 & 71.2. The NSR regulations define a "stationary source" as a "building, structure, facility, or installation" and then provide a separate definition for that phrase which reflects these three criteria. 40 C.F.R. §§ 52.21(b)(5) & (6), 51.165(a)(1)(i) & (ii), and 51.166(b)(5) & (6).

In the original promulgation of these three factors in the NSR program regulations, EPA was mindful of a decision from the U.S. Court of Appeals for the District of Columbia Circuit holding that the "source" for NSR permitting purposes should comport with the "common sense notion of a plant." 45 Fed. Reg. 52676, 52694 (Aug. 7, 1980) (citing *Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979)). When EPA first established the current three-part test in the Prevention of Significant Deterioration (PSD) NSR rules adopted in 1980, the agency explained that this test would comply with *Alabama Power* by reasonably carrying out the purposes of the PSD program, approximating a "common sense notion of a plant," and avoiding the aggregation of pollutant-emitting activities that would not fit within the ordinary meaning of "building," "structure," "facility," or "installation." 45 Fed. Reg. at 52694–95. When EPA subsequently promulgated the title V definitions for Part 71 using the same three criteria, the agency said that it intended these provisions to be consistent with the language and application of the PSD definitions. 61 Fed. Reg. 34202, 34210 (July 1, 1996).

Neither the Clean Air Act (CAA), EPA's regulations, nor Pennsylvania Department of Environmental Protection's (PADEP's) regulations define "common control." Acknowledging that "[c]ontrol can be a difficult factual determination, involving the power of one business entity to affect the construction decisions or pollution control decisions of another business entity," EPA has long recognized that common control determinations should be made on a case-by-case basis. 45 Fed. Reg. 59874, 59878 (September 11, 1980).

In an early action implementing the Nonattainment NSR program, EPA explained that it would be guided by a definition of control established by the Securities and Exchange Commission (SEC), which states the following: "the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person (or organization or association) whether through the ownership of voting shares, contract, or otherwise." 45 Fed. Reg. at 59878 (*quoting* 17 C.F.R. § 210.1-02(g)).[8] In a 1996 memorandum concerning source determinations on Federal military installations, EPA further explained:

[8] EPA has also pointed to a definition of "control" found in Webster's Dictionary, including "to exercise restraining or directing influence over," "to have power over," "power or authority to guide or manage," and "the regulation of economic activity." Letter from William A. Spratlin, Director, Air, RCRA, and Toxics Division, EPA Region 7, to Peter R. Hamlin, Chief, Air Quality Bureau, Iowa Department of Natural Resources (September 18, 1995) (the Spratlin Letter).

> In general, the controlling entity is the highest authority that exercises restraining or directing influence over a source's economic or other relevant, pollutant-emitting activities. In considering interactions among facilities, what must be determined is who has the power of authority to guide, manage, or regulate the pollutant-emitting activities of those facilities, including "the power to make or veto decisions to implement major emission-control measures" or to influence production levels or compliance with environmental regulations.[9]

In other guidance documents and letters, EPA has identified a number of factors that should be considered when assessing whether two entities are under common control, including but not limited to shared workforces, shared management, shared administrative functions, shared equipment, shared intermediates or byproducts, shared pollution control responsibilities, and support/dependency relationships.[10] In the discussion that follows, we will refer to this as the "multi-factor" approach of evaluating common control.

Regarding the support/dependency relationship factor, in several case-specific source determinations, EPA relied upon the presence of support or dependency relationships between two or more entities that resulted in one entity either directing or influencing the operations of another entity.[11] These situations often involved a primary facility that was wholly or partially dependent on a supporting facility for a critical aspect of its operations, such as the supply of raw materials. These relationships were often characterized by mutually beneficial contractual arrangements, including output contracts (where one entity was obligated to purchase all, or a portion, of another entity's output) and requirement contracts (where one entity was obligated to produce all, or a portion, of a product that another entity requires). As a result of these relationships, in certain cases EPA has found common control due to only the influence that these economically or operationally interconnected entities exert (or have the ability to exert) on one another (*e.g.*, the ability to influence production levels).

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[9] Memorandum from John S. Seitz, Director, OAQPS, to EPA Regional Offices, Major Source Determinations for Military Installations under the Air Toxics, New Source Review, and Title V Operating Permit Programs of the Clean Air Act, 9–10 (August 2, 1996) (the Seitz Memorandum) (citation omitted). Although this memorandum specifically concerned military installations, many of the statements contained therein are illustrative of EPA's past common control interpretations and policies more broadly.

[10] *See, e.g.*, Spratlin Letter at 1–2. Other EPA guidance and correspondence regarding common control can be found at: *https://www.epa.gov/title-v-operating-permits/title-v-operating-permit-policy-and-guidance-document-index* and *https://www.epa.gov/nsr/new-source-review-policy-and-guidance-document-index*.

[11] *See, e.g.*, Letter from Kathleen Cox, Associate Director, Office of Permits & Air Toxics, EPA Region 3 to Troy D. Breathwaite, Air Permits Manager, Virginia Department of Environmental Quality, Re: GPC/SPSA-Suffolk/BASF (January 10, 2012); Letter from Gregg M. Worley, Chief, Air Permits Section, EPA Region 4, to James Capp, Chief, Air Protection Branch, Georgia Department of Natural Resources, Re: PowerSecure/FEMC/Houston County Landfill (December 16, 2011); Letter from Richard R. Long, Director, Air Program, EPA Region 8, to Julie Wrend, Legal Administrator, Air Pollution Control Division, Colorado Department of Public Health and Environment, Re: TriGen/Coors (November 12, 1998); *see also* Seitz Memorandum at 10–13 (discussing control via leases and contract-for-service relationships where a supporting entity is integral to or contributes to the operations of another entity).

III. Need for Revision to EPA's Approach to Common Control Assessments

These latter precedents might be construed to suggest that EPA and PADEP should consider Meadowbrook and KSL to be under common control because of two elements of the relationship between these entities, both related to the support/dependency concept. First, the fact that KSL plans to dispose of its LFG by sending it to Meadowbrook via pipeline indicates that KSL will, in most circumstances, effectively rely on Meadowbrook as the mechanism by which it controls its LFG emissions in order to comply with Subpart WWW NSPS requirements applicable to the landfill. Second, the fact that KSL is expected to supply Meadowbrook with a potentially large proportion of the LFG that Meadowbrook processes implies that KSL could influence production levels at Meadowbrook, and thus, to some extent, Meadowbrook's emissions resulting from processing KSL's LFG. If Meadowbrook and KSL were determined to be under common control based on these facts, they would then be treated as a single source for title V and NSR purposes.[12]

On the other hand, the reasoning of other EPA source determinations involving similar facts could be followed to support the contrary conclusion that Meadowbrook and KSL are not under common control. Using the multi-factor approach to evaluating common control, one could weigh more heavily the fact that neither facility is entirely dependent on the other for operation.[13] KSL can control its LFG emissions via flaring without Meadowbrook, and Meadowbrook plans to receive gas from other entities. Additionally, Meadowbrook and KSL do not share workforces, management, administrative functions, equipment, or pollution control responsibilities. Under the multi-factor approach, these considerations suggest a lack of control.

Thus, during EPA's review of Meadowbrook's request, it became clear that the large number of different factual considerations implicated by prior EPA common control determinations, in addition to the agency's historically broad view of the types of relationships that can establish control (*e.g.*, support/dependency), has resulted in the potential for inconsistent outcomes in source determinations and an overall lack of clarity and certainty for sources and permitting authorities. Additionally, this particular scenario demonstrates practical difficulties that could result from considering these operations to be a single source, including the potential for inequitable outcomes.[14] Moreover, it was not obvious that treating Meadowbrook and KSL as a single source would reflect a "common sense notion of a plant." The potential for inconsistent outcomes under EPA's broad-ranging prior interpretations, as well as these other concerns regarding the facts at hand, have prompted EPA to reevaluate and narrow the agency's interpretation of "common control." The next section explains EPA's narrowed interpretation

[12] In its March 16, 2018, submission, Meadowbrook states that its facility will be located on a property contiguous to the KSL landfill, and that the two operations will share the same two-digit SIC code. Although Meadowbrook suggests that "shared two-digit SIC codes are unlikely to contribute any meaningful information to any aggregation analysis," this is nonetheless a criterion currently included in EPA's source determination rules.

[13] *See* Letter from Judith M. Katz, Director, Air Protection Division, EPA Region 3, to Gary E. Graham, Environmental Engineer, Commonwealth of Virginia Department of Environmental Quality, Re: Maplewood/INGENCO (May 1, 2002) (Maplewood/INGENCO letter).

[14] In particular, the agency's prior approach could lead to the impractical and potentially inequitable result of holding otherwise separate business entities responsible for each other's actions, even if they do not have the power or authority to dictate such actions.

and other considerations EPA currently views as most relevant to determining common control. The last section applies these principles in an examination of whether the Meadowbrook and KSL facilities are under common control.

IV. Refining EPA's Interpretation and Policy Concerning "Common Control"

Consistent with EPA's longstanding practice and view, determinations of common control are fact-specific and should continue to be made by permitting authorities on a case-by-case basis. However, after re-evaluating the concept of common control, EPA believes it should realign its approach to common control determinations in order to better reflect a "common sense notion of a plant," and to minimize the potential for entities to be held responsible for decisions of other entities over which they have no power or authority. For the reasons discussed further below, the agency believes clarity and consistency can be restored to source determinations if the assessment of "control" for title V and NSR permitting purposes focuses on *the power or authority of one entity to dictate decisions of the other that could affect the applicability of, or compliance with, relevant air pollution regulatory requirements.*

This document reflects EPA's interpretation of "control" in the context of EPA's title V and NSR regulations and EPA's policy regarding how to best apply this interpretation in source determinations. However, states with EPA-approved title V and NSR permitting programs retain the discretion to determine whether specific entities are under common control.[15]

A. Control means the power or authority to dictate decisions.

For purposes of source determinations, EPA considers "control" to be best understood to encompass the power or authority to dictate the outcome of decisions of another entity. This concept includes only the power to dictate a particular outcome and does not include the mere ability to influence. Thus, control exists when one entity has the power or authority to restrict another entity's choices and effectively dictate a specific outcome, such that the controlled entity lacks autonomy to choose a different course of action. This power and authority could be exercised through various mechanisms, including common ownership or managerial authority (the chain of command within a corporate structure, including parent/subsidiary relationships), contractual obligations (*e.g.*, where a contract gives one entity the authority to direct specific activities of another entity), and other forms of control where, although not specifically delineated by corporate structure or contract, one entity nonetheless has the ability to effectively direct the specific actions of another entity. Thus, control can be established: (1) when one entity has the power to command the actions of another entity (*e.g.*, Entity A expressly directs Entity B to "do X"); or (2) when one entity's actions effectively dictate the actions of another entity (*e.g.*, Entity A's actions force Entity B to do X, and Entity B cannot do anything other than X). The

[15] What follows is a discussion of those factors that EPA advises states to consider (and *not* to consider) when determining whether two entities are under common control. The general direction provided here by EPA should not be understood as controlling the outcome of any particular situation, which must be judged based on its individual facts and circumstances. This document is not a rule or regulation, and the statements herein are not binding on state or local permitting authorities. This discussion reflects a change in how EPA interprets the term "common control" in it regulations but does not change or substitute for any law, regulation, or other legally binding requirement.

second scenario that can establish control should not be confused with the broader concept, as historically articulated, embracing the "ability to influence." While distinguishing control from the ability to merely influence will necessarily be a fact-specific inquiry, the key difference is that EPA interprets "control" to exist at the point where one entity's influence over another entity effectively removes the autonomy of the controlled entity to decide whether or how to pursue a particular course of action.[16] Ultimately, the focus is not on *how* control is established (through ownership, contract, or otherwise), but on *whether* control is established—that is, whether one entity can expressly or effectively force another entity to take a specific course of action, which the other entity cannot avoid through its own independent decision-making.

This narrower interpretation of the meaning of "control" in most respects traces back to, and is consistent with, definitions of "control" on which EPA previously relied that emphasized the "power to direct,"[17] as well as a common sense understanding of "control." However, this interpretation differs from definitions that EPA has cited more recently, as well as EPA's prior interpretation of those definitions, which extended "control" to include the ability to influence.[18] For the following reasons, EPA is no longer following these broader definitions and interpretations. Certainly, business relationships and external market forces can constrain the ability of an entity to make decisions with complete autonomy, and it is indeed rare that an entity is fully insulated from such external influences. However, the fact that an entity is influenced, affected, or somewhat constrained by contractual relationships that it negotiated at arm's length, or by external market forces, does not necessarily mean that one entity is actually controlled or governed by these influences in making a given decision. After consideration of the inconsistent, impractical, and inequitable outcomes that could have resulted in this case under the previous interpretation that extended control to include the ability to influence, EPA has concluded that a narrower interpretation is better. A narrower interpretation avoids the potential for entities to be held responsible for actions over which they have no power or authority, but which instead they could merely have some influence over due to of market conditions or a business relationship that was negotiated on the open market or otherwise at arm's length. Thus, EPA will from this point forward interpret the term "control" in its title V and NSR regulations to require more than the ability to merely influence.

[16] For example, where Entity A is required to accept and process 100% of a raw material or intermediate produced by Entity B, decisions that Entity B makes with respect to the amount of raw material produced will likely affect Entity A's production levels, which could affect Entity A's emissions. However, provided that Entity A has the ability to independently decide how it operates its pollution-generating and pollution-controlling equipment, and to independently decide whether it expands its operations or not, this level of influence would not amount to "control."

[17] The common thread between definitions of "control" that EPA has relied upon is the "power to direct." *See, e.g.*, 17 C.F.R. § 210.1-02(g) (SEC definition of control, "*power to direct* or *cause the direction of* the management and policies of a person") (emphasis added); Spratlin Letter (citing Webster's definition of control, including "*to have power over*") (emphasis added).

[18] *See, e.g.*, Spratlin Letter (Webster's definition of control, including "power or authority to guide or manage," "restraining or directing influence over"); Seitz Memorandum at 9 ("restraining or directing influence"); *see also id.* at 10–13.

B. Focus should be on control over decisions that affect the applicability of, or compliance with, relevant air pollution regulatory requirements.

To promote clarity, consistency, and more practical outcomes in source determinations, EPA intends to focus on control (power or authority) over operations relevant to air pollution, and specifically control over such operations that could affect the applicability of, or compliance with, permitting requirements. EPA intends to examine whether the control exerted by one entity would determine whether a permitting requirement applies or does not apply to the other entity, or whether the control exerted by one entity would determine whether the other entity complies or does not comply with an existing permitting requirement. Thus, if "control" represents the power or authority of one entity to dictate a specific outcome at another entity (as described above), EPA considers the most relevant outcome to be the applicability of, or compliance with, air permitting requirements.

EPA considers this to be a reasonable policy, and a better approach, when determining common control in light of the applicable regulatory context. To start with, EPA's regulations reference air pollution-emitting activities when defining what constitutes a single source.[19] Definitions should not be read in isolation, however. Source determinations are made in the context of the NSR and title V permitting programs and their respective requirements pertaining to the control and monitoring of air pollution emissions. It logically follows, therefore, that the type of "control" most relevant to this inquiry is control over air pollution-emitting activities that trigger permitting requirements and affect compliance with those requirements. EPA therefore considers it appropriate to focus this inquiry on control over air pollution-emitting activities that could affect the applicability of, or compliance with, title V and NSR requirements.[20] If the authority one entity has over another cannot actually affect the applicability of, or compliance with, relevant permitting requirements, then the entities cannot control what permit requirements are applicable to each other, or whether another entity complies with its respective requirements. Effectively, this means that each entity has autonomy with respect to its own permitting obligations. It is more logical for such entities to be treated as separate sources, rather than being artificially grouped together for permitting purposes. EPA expects that any benefit that might be thought to be gained from the aggregation of entities that are effectively autonomous for permitting purposes would not "carry out reasonably the purposes" of the title V or NSR program. *See* 45 Fed. Reg. at 525694–95.[21]

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[19] *See, e.g.*, 40 C.F.R. § 52.21(b)(6) (defining "building, structure, facility, or installation" as "all of the *pollutant-emitting activities*" that are under common control, among other criteria (emphasis added)); 40 C.F.R. § 70.2 (clarifying that for the definition of "major source," considerations of major industrial group (SIC code) should focus on "all of the *pollutant emitting activities* at such source or group of sources" (emphasis added)); *id.* (defining "stationary source" as "any building, structure, facility, or installation *that emits or may emit* any regulated air pollutant or any pollutant listed under section 112(b) of the [CAA]") (emphasis added); 40 C.F.R. 52.21(b)(5) (similar definition of "stationary source" for NSR).

[20] EPA has previously articulated the importance of similar considerations, including "the power to make or veto decisions to implement major emission-control measures," and the power to influence "compliance with environmental regulations." Seitz Memorandum at 10 (citations omitted).

[21] First, although a more expansive reading of control could result in more sources being subject to title V, the purpose of the title V program is *not* to indiscriminately maximize the number of sources required to obtain operating permits—such as by requiring small sources that would otherwise not be subject to title V to obtain a

Moreover, aggregating entities that cannot control decisions affecting applicability or compliance with permitting and other requirements would create practical difficulties and inequities. For title V purposes, it may be impossible for the responsible official of one entity to accurately certify the completeness of a permit application for a permit modification (*e.g.*, to incorporate requirements that are applicable to a new unit) that is entirely within the control of another entity, or to certify that the other entity has complied with existing permit requirements, as required by title V. *See* 40 C.F.R. § 70.5(a)(2), (c)(9)(i), (d). Similar problematic scenarios can arise under the NSR program as well. For instance, in order to determine whether a proposed physical or operational change would result in a "significant net emissions increase" and thus constitute a "major modification" at the source, an entity is required to identify and take account of all creditable emissions increases and decreases that had occurred source-wide during the relevant 5-year "contemporaneous" period. *See, e.g.*, 40 C.F.R. § 52.21(b)(3)(i)(*b*). It is not clear how it would even be possible for one entity to identify the creditable emissions increases and decreases that had occurred at that portion of the source under the control of another entity, much less determine whether NSR would be triggered by the proposed change.

More broadly, for both title V and NSR, an entity could face liability for the actions of another entity that were entirely outside the first entity's control if both entities were treated as part of the same source. This result would clearly be inequitable. Put simply, an entity that cannot "direct" or "cause the direction of" a specific decision or action by another entity does not have "control" and should not be subject to the consequences of that decision.[22] Focusing on control over decisions that could affect applicability or compliance with air quality permitting obligations avoids this potentially impractical and inequitable result while reasonably carrying out the purposes of the title V and NSR permitting programs.

In practice, evaluating common control will necessarily be a fact-specific inquiry. However, EPA believes the most relevant considerations should be whether entities have the power to direct the actions of other entities to the extent that they affect the applicability of and compliance with permitting requirements: *e.g.*, the power to direct the construction or modification of equipment that will result in emissions of air pollution; the manner in which such emission units operate; the installation or operation of pollution control equipment; and

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permit simply because of their business relationships with a title V source. Second, the purpose of the NSR program is not to maximize the number of sources subject to PSD requirements (*e.g.*, BACT) by aggregating multiple entities until their combined emissions exceed major source thresholds. That said, it would also not be appropriate to rely on EPA's current approach to artificially separate a source into multiple sources in order to evade major source status or otherwise circumvent title V or NSR requirements. Third, the purposes of the NSR program would not be fulfilled by allowing entities to intentionally (or unintentionally) over-aggregate, in order to share the benefits of emissions reductions (*e.g.*, accounting for emission reductions in determining a significant net emissions increase) at sources that do not have any control over each other's permitting obligations. EPA's current approach is intended to avoid these outcomes that are incongruent with the purposes of the title V and NSR programs by aggregating only those activities that accurately reflect a "common sense notion of a plant" from a permitting standpoint.

[22] For example, if Entity A has no ability to dictate the relevant decisions of Entity B that would subject Entity B to new regulatory requirements or that would affect Entity B's compliance with existing requirements, it would be inequitable to subject Entity A to such new requirements or hold Entity A responsible for Entity B's compliance with existing requirements. Only if Entity A has the ability to dictate an action by Entity B that could result in permitting-related liability for either entity, should Entity A be held responsible for Entity B's action (by virtue of being considered the same source).

monitoring, testing, recordkeeping, and reporting obligations. On the other hand, common control considerations should not focus on the power to direct aspects of an entity's operations that are wholly unrelated to air pollution permitting requirements. If one entity has power or authority over some aspect of another entity's operations that would have no impact on pollutant-emitting activities of the stationary source subject to permitting requirements, EPA does not consider that fact to be relevant to determining whether the two entities should be considered a single source for air quality permitting purposes (*e.g.*, one entity providing security for both its facility and for an adjacent facility belonging to another entity).

Overall, focusing on the power to direct decisions over air pollution-related activities that could affect permitting obligations (*i.e.*, applicability or compliance) is reasonable, and a better approach to determining whether there is common control in the context of title V and NSR permitting. EPA expects that this approach will produce more consistent and sensible outcomes. Accordingly, EPA will generally view common control to exist in situations where entities lack the power or authority to make independent decisions that could affect the applicability of, or compliance with, relevant regulatory requirements concerning air pollution.

C. Dependency relationships should not be presumed to result in common control.

It is important, in evaluating whether common control might be said to exist due to the existence of a dependency relationship between entities, not to confuse this evaluation with the altogether separate issue of whether one entity is a "support facility" for another entity. Questions arising out of the consideration of the latter issue are directly accommodated within a distinct element of the source determination framework: the industrial grouping (2-digit SIC code) prong.[23] EPA has previously stated that "a support facility analysis is only relevant under the SIC-code determination." *In the Matter of Anadarko Petroleum Corp., Frederic Compressor Station*, Order on Petition no. VIII-2010-4 at 16 (February 2, 2011). This important distinction aside, a dependency relationship should not be presumed to result in common control. While mutually beneficial arrangements that give rise to dependency relationships could give one facility influence over the operations of another, entities can be economically or operationally interconnected or mutually dependent through contracts or other business arrangements without having the power or authority to direct the relevant activities of each other. To the extent that the same underlying facts should be weighed in evaluating common control, these considerations should generally be evaluated as outlined above to determine whether one entity has the power or authority to dictate the decisions of another entity (and not simply to determine whether a dependency relationship exists).

[23] As EPA has explained, both primary and support facilities are to be assigned the same 2-digit SIC code. 45 Fed. Reg. at 52695; *see also* 1987 SIC Code Manual at 16–17 ("Each operating establishment is assigned an industry code on the basis of its primary activity . . . . Auxiliary establishments are assigned four-digit industry codes on the basis of the primary activity of the operating establishments they serve."). In the PSD rulemaking process conducted from 1979 to 1980, EPA decided to accommodate considerations of support or functional interrelatedness as part of the major industrial grouping (2-digit SIC code) prong, as opposed to establishing this as an independent component of the source determination analysis. *See* 45 Fed. Reg. 52676, 52695 (August 7, 1980). In so doing, EPA did not indicate that support or functional interrelatedness considerations should be made in the context of other discrete elements of the source determination framework (*i.e.*, the common control or adjacency prongs).

A number of practical considerations support this separation. First, the fact that economic conditions are such that one entity depends on another facility does not necessarily mean that it has the power or authority to direct the decisions of, or that its decisions are directed by, that other facility on which it depends. Second, the fact that one facility would not profitably exist *but for* the existence of another entity does not necessarily mean that, at some point after beginning operation, the entities will have the power or authority to dictate the outcome of decisions regarding relevant air-pollution related aspects of each other's operations. These situations should be evaluated in light of the principles discussed above, and inquiries concerning common control should not be sidestepped by presuming control based on the presence of a dependency relationship.

V. Evaluation of Meadowbrook and KSL Under Revised Interpretation and Policy for Common Control

Applying the interpretation of "common control" and the policy of focusing on air permitting requirements described above, based on the information provided by Meadowbrook,[24] EPA would not view the Meadowbrook and KSL facilities to be under common control. First, regarding control over KSL's landfill, it does not appear that Meadowbrook has power or authority to dictate decisions over any aspect of KSL's operations that could affect the applicability of, or compliance with, permitting requirements. Specifically, Meadowbrook does not have the power or authority to determine whether KSL complies with regulatory requirements associated with its LFG (*i.e.*, the Subpart WWW NSPS) that are applicable requirements within KSL's title V permit. Of course, Meadowbrook can indirectly affect KSL's operations by declining to take delivery of all of KSL's LFG at the demarcation point (or by ceasing operations). This means that Meadowbrook's actions (accepting or not accepting the LFG) would effectively dictate whether KSL does or does not destroy its LFG via its flares. Because Meadowbrook can effectively dictate this outcome at KSL, this could arguably be considered a form of control over this aspect of KSL's operations. However, this limited amount of control would not be over operations that EPA finds most relevant. Importantly, Meadowbrook will not affect KSL's ability to comply with its regulatory obligations since KSL retains the ability to redirect its LFG to flares operated exclusively by KSL and Meadowbrook has no power or authority over how KSL operates such flares.[25] Because Meadowbrook therefore has no power or authority over KSL's operations of the sort that EPA deems most relevant, *i.e.*, KSL's ability to comply with relevant permitting requirements, EPA's view is that

[24] EPA notes that some of the analysis initially provided by Meadowbrook and supplemented in its March 16, 2018, analysis is based on an agreement between Meadowbrook and KSL that is subject to revision. EPA's analysis below is based on the representations provided by Meadowbrook, and should not be interpreted as a complete evaluation of all facts that may be relevant to the question of common control. PADEP, as the permitting authority, is responsible for making a source determination based on all relevant facts, which may extend to current factual considerations that were not included in Meadowbrook's analysis, or to facts that eventually differ from those that Meadowbrook predicted at the time of its March 16, 2018, submittal.

[25] This situation is no different from a landfill that utilizes flares as a control device and naturally has no other options to dispose of its LFG (*e.g.*, no ability to send the LFG to a treatment facility or energy generating facility). In either case, even if the landfill has only one general option to dispose of its gas (flaring), it would nonetheless likely retain complete control over whether and how it does so (including whether it complies with relevant regulatory requirements when doing so).

Meadowbrook does not control KSL simply because KSL will ordinarily rely on Meadowbrook as a means of disposing of its LFG.[26] There is no indication that Meadowbrook has any power or authority over other activities occurring at KSL.[27]

Second, regarding control over Meadowbrook's operations, although KSL supplies Meadowbrook with a potentially large percentage of the feedstock (LFG) that Meadowbrook processes into a product for market (pipeline-quality renewable natural gas), it does not appear that this arrangement gives KSL power or authority over Meadowbrook's operations. Operations at KSL could ultimately affect the amount of LFG available to Meadowbrook, and thus, could indirectly affect the air emissions that ultimately occur at Meadowbrook in the course of processing the LFG. But it does not appear that Meadowbrook is contractually obligated to purchase the full output of KSL (although this may typically be the case).[28] Moreover, Meadowbrook indicated that it is actively pursuing other suppliers of feedstock, such that KSL will likely not be the only supplier of LFG (or other gas feedstock) to KSL. Thus, KSL does not have the power or authority to determine the amount of gas received (and therefore processed) by Meadowbrook. To the extent that decisions by KSL could indirectly impact air emissions at Meadowbrook, there is no indication that this would give KSL power or authority over any of Meadowbrook's air pollution-related operations, much less affect any permitting obligations applicable to Meadowbrook. At most, this amounts to influence, not control. Therefore, it would be appropriate to conclude that KSL does not control Meadowbrook in the sense relevant for determining whether the two entities' facilities constitute a single source. KSL simply supplies a feedstock product to Meadowbrook through an arm's length contract. KSL has no power or authority to direct other aspects of Meadowbrook's operations, including the means by which Meadowbrook generates and controls emissions.

Although Meadowbrook and KSL have at least influence over each other's operations, neither has "control" (as this term is interpreted above) over decisions that could affect air permitting obligations of the other. Rather, this appears to be, as Meadowbrook claimed, a mutually beneficial arms-length arrangement between two wholly-separate business entities. Therefore, EPA does not recommend that Meadowbrook and KSL be considered to be part of the same stationary source or major source on the basis of common control. However, as the permitting authority, PADEP retains the ultimate discretion to make source determinations based on its EPA-approved title V and NSR rules.

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[26] This conclusion is premised on Meadowbrook's representation that KSL's permit would not be modified in such a manner that Meadowbrook would have the power or authority to dictate whether KSL complies with its permit terms.

[27] Although Meadowbrook may supply funding or other resources to KSL for purposes of optimizing KSL's landfill gas recovery system, Meadowbrook's representations suggest that KSL would nonetheless retain complete control over this optimization process, and that Meadowbrook would not control any aspect of the LFG collection process. Additionally, the limited information presented by Meadowbrook regarding its potential future use of KSL's leachate, condensate, and wastewater treatment systems at market prices does not indicate that this would result in Meadowbrook's control over this aspect of KSL's operations. However, this arrangement may warrant further evaluation as Meadowbrook and KSL finalize their plans.

[28] As noted above, Meadowbrook indicated that it is only required to accept as much LFG as Meadowbrook can process.

Draft Title V Permit to Operate No. T5-F84011

NORTH DAKOTA
DEPARTMENT *of* HEALTH

ENVIRONMENTAL HEALTH SECTION
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Bismarck, ND 58501-1947
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AIR POLLUTION CONTROL
TITLE V PERMIT TO OPERATE

Permittee: **Name:** Montana-Dakota Utilities, Co. North Western Public Service Company Northern Municipal Power Agency (Minnkota Power Cooperative, Inc.) Otter Tail Power Company **Address:** Otter Tail Power Company 215 South Cascade Street P.O. Box 496 Fergus Falls, MN 56538-0496	**Permit Number:** T5-F84011 **Source Name:** Coyote Station
Source Location: Sec. 10, S½ of S½ of Sec. 3 and W½ of Sec. 11, T143N, R88W 6240 - 13th Street SW Beulah, ND 58523 Mercer County	**Source Type:** Electric Generating Unit; Coal
Expiration Date: September 17, 2023	

Pursuant to Chapter 23-25 of the North Dakota Century Code, and the Air Pollution Control Rules of the State of North Dakota, Article 33-15 of the North Dakota Administrative Code (NDAC), and in reliance on statements and representations heretofore made by the permittee (i.e., owner) designated above, a Title V Permit to Operate is hereby issued authorizing such permittee to operate the emissions units at the location designated above. This Title V Permit to Operate is subject to all applicable rules and orders now or hereafter in effect of the North Dakota Department of Health and to any conditions specified on the following pages. All conditions are enforceable by EPA and citizens under the Clean Air Act unless otherwise noted.

Renewal No. 4: TBD
Revision No. 0: ______

Terry L. O'Clair, P.E.
Director
Division of Air Quality

Coyote Station
Title V Permit to Operate
Table of Contents

Permit Shield

Compliance with the terms and conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that:

- Such applicable requirements are included and are specifically identified in this permit; or
- The Department, in acting on the permit application or revision, determines in writing that other requirements specifically identified are not applicable to the source, and the determination, or a concise summary thereof, is included in this permit.

Applicable Requirement: NDAC 33-15-14-06.5.f(1)

1. **Emission Unit Identification**:

The emission units regulated by this permit are as follows:

A. Point Sources:

Emission Unit Description	Emission Unit (EU)	Emission Point (EP)	Air Pollution Control Equipment
Unit 1 boiler lignite-fired cyclone with a nominal rated heat input capacity of 5,800 x 10^6 Btu/hr	1	1	Fabric Filter, Spray Dryer Scrubber, Separated Over Fire Air, and Activated Carbon Injection
Auxiliary boiler No. 2 fuel oil-fired with a nominal rated heat input capacity of 202 x 10^6 Btu/hr	2	2	None
Facility 1,440 hp diesel engine-driven emergency generator (1977)	4 [A]	4	None
Fire pump 225 hp emergency diesel engine (1977)	5	5	None
Scrubber 1,375 hp Kohler Model 900ROZD diesel engine-driven emergency generator (1991)	6 [A]	6	None
Transfer house	M2	M2	Baghouse
Northside distribution building	M3	M3	Baghouse
Southside distribution building	M4	M4	Baghouse
Lime storage silo	M5	M5	Baghouse
Recycle fly ash silo	M6	M6	Baghouse
Fly ash silo	M7	M7	Baghouse
Lime unloading bin vent filter	M9	M9	Baghouse
Carbon silo bin vent filter	M10 [B]	M10	Baghouse
No. 2 fuel oil tank (1,000,000 gallons)	T1 [B]	T1	None
No. 2 fuel oil tank (998,088 gallons)	T2 [B]	T2	None

A The potential to emit for an emergency stationary reciprocating internal combustion engine (RICE) is based on operating no more hours per year than is allowed by the subpart (40 CFR 63, Subpart ZZZZ) for other than emergency situations. For engines to be considered emergency stationary RICE under the RICE rules, engine operations must comply with the operating hour limits as specified in the applicable subpart. There is no time limit on the use of emergency stationary RICE in emergency situations.

B Insignificant or fugitive emission sources (no specific emission limit).

B. Fugitive Emissions Sources:

1) Inactive coal storage pile

2) 161,000 gpm cooling tower

3) Coal conveying/handling equipment

C. Continuous Emission Monitoring System (CEMS): Emissions from EU 1 (EP 1) are monitored by CEMS for the following pollutants/parameters: Opacity, SO_2, NO_x, CO_2 and flow.

2. **Fuel Restrictions**:

A. EU 1 shall be operated using lignite coal as the primary fuel and subbituminous coal and petroleum coke as supplemental fuels. During startup and unstable firing conditions in a cyclone boiler, No. 2 fuel oil may be utilized.

1) State Enforceable Only - Burning of used oil in EU 1 is allowed subject to the following:

a) The burning of used oil shall comply with NDAC Sections 33-24-05-600 through 33-24-05-689 - Standards for the Management of Used Oil - and other applicable rules, regulations, and ordinances.

b) Only oil which contains less than 50 ppm PCB may be burned. Burning of oil which contains PCB is only allowed for used oil generated by Otter Tail Power Company, its associated electric system, or its associated mining facilities.

c) Debris contaminated with mineral oil dielectric fluid which contains less than 50 ppm PCB may be burned during periods of stable load.

d) The annual emission inventory reports required by Condition 9.F shall include the amount of used oil burned.

B. EU 2 shall be operated using only No. 2 fuel oil.

C. The permittee shall purchase or otherwise obtain only distillate oil containing no more than 0.0015 percent sulfur by weight for the operation of the engines (EU 4, 5 and 6).

Fuels, other than those listed above, may be burned if approved in advance by the Department and compliance with applicable emission limits and standards are maintained.

Applicable Requirement: NDAC 33-15-14-06.5.b(1)

3. **Applicable Standards and Miscellaneous Conditions**:

A. **New Source Performance Standards (NSPS)**: The permittee shall comply with all applicable requirements of the following NDAC 33-15-12-02 and 40 CFR 60 subparts in addition to complying with Subpart A – General Provisions.

1) Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction Is Commenced After August 17, 1971 (Unit 1 boiler, EU 1).

2) Subpart Y – Standards of Performance for Coal Preparation Plants (EU M2, M3 and M4).

Applicable Requirements: NDAC 33-15-12, Subparts A, D and Y

B. **Maximum Achievable Control Technology (MACT)**: The permittee shall comply with all applicable requirements of the following NDAC 33-15-22-03 and 40 CFR 63 subparts in addition to complying with Subpart A - General Provisions.

1) Subpart ZZZZ (4Z) – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (EU 4, 5 and 6).

2) Subpart DDDDD (5D) – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters (EU 2).

a) EU 2 is classified as a *limited-use boiler*. In order to maintain *limited-use boiler* classification as defined by 40 CFR 63 Subpart DDDDD, EU 2 shall combust no more than 1,263,943 gallons of No. 2 fuel oil per calendar year, which corresponds to an average annual capacity factor of 10 percent.

Applicable Requirement: Permit to Construct (PTC)13032 and NDAC 33-15-22-03, Subpart DDDDD

3) Subpart UUUUU (5U) – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units (EU 1).

Applicable Requirements: NDAC 33-15-22-03, Subparts A, ZZZZ, DDDDD and UUUUU

4. **Emission Unit Limits:**

A. **Emission Limits:**

Emission Unit Description	EU	EP	Pollutant/ Parameter	Emission Limit	NDAC Applicable Requirement
Unit 1 boiler	1	1	PM	0.10 lb/10^6 Btu[d] & 0.03 lb/10^6 Btu[f] & 445 lb/hr[a]	33-15-12, Subpart D, 33-15-22, Subpart 5U & PTC 8/9/77
			SO_2	1.2 lb/10^6 Btu[b] & 5,335 lb/hr[e]	33-15-12, Subpart D & PTC 8/9/77
			NO_x	3,910 lb/hr[c] & 0.50 lb/10^6 Btu[g]	PTC 8/9/77 & PTC10008 Rev. 1
			HCl	0.002 lb/10^6 Btu[f]	33-15-22, Subpart 5U
			Hg	4.0 lb/10^{12} Btu[f]	33-15-22, Subpart 5U
			Opacity	Cond. 4.B.1 & 4.B.2	33-15-12, Subparts A & D & 33-15-03-02
Auxiliary boiler	2	2	PM	2.9 lb/hr[a] & 0.40 lb/10^6 Btu[a]	PTC 8/9/77 & 33-15-05
			SO_2	3.0 lb/10^6 Btu[e] & 102.6 lb/hr[e]	PTC 8/9/77 & 33-15-06
			NO_x	31.8 lb/hr[a]	PTC 8/9/77
			Opacity	Cond. 4.B.1	33-15-03-02
Facility emergency generator engine	4	4	PM	2.6 lb/hr[a]	PTC 8/9/77
			SO_2	1.7 lb/hr[a]	PTC 8/9/77
			NO_x	35.6 lb/hr[a]	PTC 8/9/77
			Opacity	Cond. 4.B.1	33-15-03-02
			Operating Hours	Cond. 1 Footnote [A]	33-15-14-06.4.c(3)(2) & 33-15-22-03, Subpart 4Z

Emission Unit Description	**EU**	**EP**	**Pollutant/ Parameter**	**Emission Limit**	**NDAC Applicable Requirement**
Fire pump emergency engine	5	5	PM SO_2 NO_x Opacity Operating Hours	1.0 lb/hr[a] 0.94 lb/hr[a] 14.1 lb/hr[a] Cond. 4.B.1 Cond. 1 Footnote [A]	PTC 8/9/77 PTC 8/9/77 PTC 8/9/77 33-15-03-02 33-15-14-06.4.c(3)(2) & 33-15-22-03, Subpart 4Z
Scrubber emergency generator engine	6	6	NO_x SO_2 CO Opacity Operating Hours	33.9 lb/hr[a] 4.3 lb/hr[a] 8.8 lb/hr[a] Cond. 4.B.1 Cond. 1 Footnote [A]	PTC 12/7/92 PTC 12/7/92 PTC 12/7/92 33-15-03-02 33-15-14-06.4.c(3)(2) & 33-15-22-03, Subpart 4Z
Transfer house	M2	M2	PM Opacity	1.42 lb/hr[a] Cond. 4.B.1 & 4.B.3	PTC 8/9/77 33-15-12, Subparts A & Y & 33-15-03-02
Northside distribution building	M3	M3	PM Opacity	5.66 lb/hr[a] Cond. 4.B.1 & 4.B.3	PTC 8/9/77 33-15-12, Subparts A & Y & 33-15-03-02
Southside distribution building	M4	M4	PM Opacity	4.87 lb/hr[a] Cond. 4.B.1 & 4.B.3	PTC 8/9/77 33-15-12, Subparts A & Y & 33-15-03-02
Lime storage silo	M5	M5	PM Opacity	33.52 lb/hr[a] Cond. 4.B.1	33-15-05-01 33-15-03-02
Recycle fly ash silo	M6	M6	PM Opacity	50.82 lb/hr[a] Cond. 4.B.1	33-15-05-01 33-15-03-02
Fly ash silo	M7	M7	PM Opacity	33.31 lb/hr[a] Cond. 4.B.1	33-15-05-01 33-15-03-02

Emission Unit Description	EU	EP	Pollutant/ Parameter	Emission Limit	NDAC Applicable Requirement
Lime unloading bin vent filter	M9	M9	PM Opacity	5.7 lb/hr[a] Cond. 4.B.1	33-15-05-01 33-15-03-02

[a] (1-hour average)

[b] (3-hour rolling average). This standard does not apply during startup, shutdown and malfunction.

[c] (12-month rolling average)

[d] (1-hour average). This standard does not apply during startup, shutdown and malfunction.

[e] (3-hour rolling average)

[f] 30 boiler operating day rolling average (bodra). The emission rate shall be calculated in accordance with 40 CFR 63, Subpart UUUUU.

[g] (30-day rolling average)

B. **Opacity Limits:**

1) All emission units - twenty percent (six-minute average), except that a maximum of forty percent (six-minute average) is permissible for not more than one six-minute period per hour. This standard applies at all times.

2) EU 1 - In addition to the opacity limit specified in Condition 4.B.1, twenty percent (six-minute average), except that a maximum of twenty-seven percent (six-minute average) is permissible for not more than one six-minute period per hour. This standard does not apply during startup, shutdown and malfunction.

3) EU M2, M3, and M4 - In addition to the opacity limit specified in Condition 4.B.1, twenty percent opacity (six-minute average) or greater shall not be discharged into the atmosphere. This standard does not apply during startup, shutdown and malfunction.

Applicable Requirements: NDAC 33-15-12, Subparts A, D and Y, and NDAC 33-15-03-02

5. **Monitoring Requirements and Conditions:**

A. **Requirements:**

Emission Unit Description	EU	Pollutant/ Parameter	Monitoring Requirement (Method)	Condition Number	NDAC Applicable Requirement
Unit 1 boiler	1	PM	Compliance Assurance Monitoring (CAM) & Emissions Test	5.B.1, 5.B.8 & 5.B.10	33-15-14-06.10, 33-15-14-06.5.a(3)(a), 33-15-12, Subpart D, 33-15-21, & 33-15-22-03, Subpart 5U
		SO_2	Continuous Emission Monitoring System (CEMS)	5.B.1, 5.B.3 & 5.B.4	33-15-14-06.5.a(3)(a)
		NO_x	CEMS	5.B.1, 5.B.3, 5.B.4 & 5.B.11	33-15-14-06.5.a(3)(a) & PTC10008 Rev. 1
		CO_2	CEMS	5.B.1, 5.B.3, 5.B.4 & 5.B.11	33-15-12, Subpart D, 33-15-21 & PTC10008 Rev. 1
		Hg	Sorbent Trap System/Continuous Monitoring	5.B.1	33-15-22-03, Subpart 5U
		HCl	Emissions Test	5.B.1	33-15-22-03, Subpart 5U
		Opacity	COMS/O&M (Operations & Maintenance)	5.B.1, 5.B.2, 5.B.3, 5.B.4 &5.B.7	33-15-21
		Flow	Flow Monitor	5.B.1, 5.B.3 & 5.B.4	33-15-21

Emission Unit Description	**EU**	**Pollutant/ Parameter**	**Monitoring Requirement (Method)**	**Condition Number**	**NDAC Applicable Requirement**
Auxiliary boiler	2	PM	Recordkeeping	5.B.5	33-15-14-06.5.a(3)(a)
		SO_2	Recordkeeping	5.B.5	33-15-14-06.5.a(3)(a)
		NO_x	Emissions Test	5.B.6	33-15-14-06.5.a(3)(a)
		Opacity	Recordkeeping	5.B.5	33-15-14-06.5.a(3)(a)
		Operating Hours & Gallons of No. 2 Fuel Oil Combusted	Recordkeeping	5.B.9	33-15-14-06.5.a(3)(a)
Facility emergency generator engine	4	PM	Recordkeeping	5.B.5	33-15-14-06.5.a(3)(a)
		SO_2	Recordkeeping	5.B.5	33-15-14-06.5.a(3)(a)
		NO_x	Emissions Test	5.B.6	33-15-14-06.5.a(3)(a)
		Opacity	Recordkeeping	5.B.5	33-15-14-06.5.a(3)(a)
		Operating Hours	Recordkeeping	5.B.9	33-15-14-06.5.a(3)(a)
Fire pump emergency engine	5	PM	Recordkeeping	5.B.5	33-15-14-06.5.a(3)(a)
		SO_2	Recordkeeping	5.B.5	33-15-14-06.5.a(3)(a)
		NO_x	Emissions Test	5.B.6	33-15-14-06.5.a(3)(a)
		Opacity	Recordkeeping	5.B.5	33-15-14-06.5.a(3)(a)
		Operating Hours	Recordkeeping	5.B.9	33-15-14-06.5.a(3)(a)
Scrubber emergency generator engine	6	NO_x	Emissions Test	5.B.6	33-15-14-06.5.a(3)(a)
		SO_2	Recordkeeping	5.B.5	33-15-14-06.5.a(3)(a)
		CO	Emissions Test	5.B.6	33-15-14-06.5.a(3)(a)
		Opacity	Recordkeeping	5.B.5	33-15-14-06.5.a(3)(a)
		Operating Hours	Recordkeeping	5.B.9	33-15-14-06.5.a(3)(a)
Transfer house	M2	PM/Opacity	CAM	5.B.10	33-15-14-06.10
Northside distribution building	M3	PM/Opacity	CAM	5.B.10	33-15-14-06.10
Southside distribution building	M4	PM/Opacity	CAM	5.B.10	33-15-14-06.10

Emission Unit Description	EU	Pollutant/ Parameter	Monitoring Requirement (Method)	Condition Number	NDAC Applicable Requirement
Lime storage silo	M5	PM/Opacity	CAM	5.B.10	33-15-14-06.10
Recycle fly ash silo	M6	PM/Opacity	CAM	5.B.10	33-15-14-06.10
Fly ash silo	M7	PM/Opacity	CAM	5.B.10	33-15-14-06.10
Lime unloading bin vent filter	M9	PM/Opacity	CAM	5.B.10	33-15-14-06.10

B. **Monitoring Conditions**:

1) The monitoring shall be in accordance with the following applicable requirements of Chapter 33-15-06, Chapter 33-15-12, Chapter 33-15-21 and Chapter 33-15-22 of the North Dakota Air Pollution Control Rules (NDAC). Emissions are calculated using 40 CFR 75, Appendix F and 40 CFR 60, Appendix A.

   a) NDAC, §33-15-06-04, Monitoring Requirements.

   b) 40 CFR 60, Subpart A, §60.13, Monitoring Requirements.

   c) 40 CFR 60, Subpart D §60.45, Emission and Fuel Monitoring.

   d) NDAC, §33-15-21-09, Monitoring Requirements.

   e) 40 CFR 63, Subpart A, §63.8, Monitoring Requirements.

   f) 40 CFR 63, Subpart DDDDD, §63.7535 through §63.7541, Continuous Compliance Requirements

   g) 40 CFR 63, Subpart UUUUU, §63.10020, Continuous Compliance Requirements

2) The permittee shall conduct performance evaluations of the continuous opacity monitoring system with quarterly performance audits and annual zero alignments in accordance with 40 CFR 60 Appendix F, Procedure 3. For the performance evaluation, conformance with the specification for calibration error, Section 13.3 Field Audit Performance Specifications, Paragraph (2) Calibration Error of 40 CFR 60, Appendix B, Performance Specification 1 must be demonstrated. Quarterly assessments may be reduced in frequency to semi-annual with four consecutive quarters of quality-assured data (40 CFR 60 Appendix F, Procedure 3, Section 2.0). The requirements of 40 CFR 60, Appendix F, Procedure 3 include daily calibration checks, quarterly performance audits and annual primary zero alignment under clear path conditions. The procedures of Section 8.1, paragraph (3)(ii) Calibration Check of 40 CFR 60, Appendix B, Performance Specification 1 shall be used to determine conformance with the specification for calibration error.

3) The Department may require additional performance audits of the CEMS.

4) When a failure of a continuous emission monitoring system occurs, an alternative method, acceptable to the Department, for measuring or estimating emissions must be undertaken as soon as possible. The provisions outlined in 40 CFR 75, Subpart D for data substitution are considered an acceptable method. Timely repair of the emission monitoring system must be made.

5) For purposes of compliance monitoring, for EU 2, 4, 5 and 6, burning of fuels as outlined in Conditions 2.B and 2.C shall be considered credible evidence of compliance with any applicable opacity, particulate and SO_2 emission limit. However, results from tests conducted in accordance with the test methods in 40 CFR 50, 51, 60, 61, or 75 will take precedence over burning fuels as outlined in Conditions 2.B and 2.C for evidence of compliance or noncompliance with any applicable opacity, particulate, SO_2, and CO emission limit, in the event of enforcement action.

6) To provide a reasonable assurance of compliance, an emissions test for EU 4, 5 or 6 shall be conducted to measure NO_x and CO emissions, as applicable, when the emissions unit has operated more than is allowed by the applicable subpart (40 CFR 63, Subpart ZZZZ) to be defined as "emergency." For EU 4, 5 or 6, additional emission limits and testing may apply for compliance with the applicable subpart (see Condition 3.B.1). For EU 2, an emissions test shall be conducted to measure NO_x emissions when the emissions unit has operated more than 500 hours in a calendar year and has combusted more than 720,000 gallons of No. 2 fuel oil in a calendar year. The test shall be conducted using, at a minimum, a portable analyzer with quality assurance procedures equivalent to Conditional Test Methods 22 and/or 30 as outlined in EPA's Emission Measurement Center or the Department's Standard Operating Procedures, Use of Portable Analyzer for Title V Semi-Annual Testing. A test shall consist of three runs, with each run at least 20 minutes in length.

7) The permittee shall maintain and operate air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. The manufacturer's recommended Operations and Maintenance (O&M) procedures, or a site-specific O&M procedure (developed from the manufacturer's recommended O&M procedures), shall be followed to assure proper operation and maintenance of the equipment. The permittee shall have the O&M procedures available on site and provide the Department with a copy when requested.

8) Any time within one year of permit expiration, the permittee shall conduct an emissions test to measure particulate emissions, using EPA Test Methods in 40 CFR 60, Appendix A. A test shall consist of three runs, with each run at least one hour in length. Other test methods may be used provided they are approved, in advance, by the Department.

Note: This requirement may be satisfied if recurring testing is otherwise performed in accordance with requirements under 40 CFR 63, Subpart UUUUU.

9) A log shall be kept of the hours of operation. For EU 2, a record of gallons of No. 2 fuel oil combusted shall also be kept.

10) EU 1, M2, M3, M4, M5, M6, M7 and M9 are subject to Compliance Assurance Monitoring (CAM) requirements with respect to particulate matter. The CAM plan is in Attachment A of this permit. The permittee shall conduct the monitoring, recordkeeping and reporting as required by the applicable subparts of 40 CFR 64.

11) The permittee shall maintain and operate air pollution control monitoring equipment in a manner consistent with the manufacturer's recommended procedures or site-specific QA/QC Plan required by 40 CFR 75. The permittee shall have the QA/QC Plan available on-site and provide the Department with a copy when requested.

6. **Recordkeeping Requirements**:

A. The permittee shall maintain compliance monitoring records as outlined in the Monitoring Records table that include the following information.

1) The date, place (as defined in the permit) and time of sampling or measurement.

2) The date(s) testing was performed.

3) The company, entity, or person that performed the testing.

4) The testing techniques or methods used.

5) The results of such testing.

6) The unit load and operating conditions that existed at the time of sampling or measurement.

Applicable Requirement: NDAC 33-15-14-06.5.a(3)(b)[1]

7) The records of quality assurance for emissions measuring systems including by not limited to quality control activities, audits and calibration drifts as required by the applicable test method for EU 1.

8) A copy of all field data sheets from the emissions testing for EU 1.

9) A record shall be kept of all major maintenance activities conducted on the emission unit or air pollution control equipment for EU 1.

Applicable Requirement: PTC10008 Rev. 1

Monitoring Records

Emission Unit Description	EU	Pollutant/ Parameter	Compliance Monitoring Record
Unit 1 boiler	1	PM	CAM Data & Emissions Test Data
		SO_2	CEMS Data
		NO_x	CEMS Data
		CO_2	CEMS Data
		Hg	Sorbent Trap System/Continuous Monitoring Data
		HCl	Emissions Test Data
		Opacity	COMS Data & O&M Data
		Flow	Flow Monitor Data
Auxiliary boiler	2	PM	Type of Fuel Usage
		SO_2	Type of Fuel Usage
		NO_x	Emissions Test Data
		Opacity	Type of Fuel Usage
		Operating Hours & Gallons of Fuel	Hours of Operation & Gallons of Fuel Data
Facility emergency generator engine	4	PM	Type of Fuel Usage
		SO_2	Type of Fuel Usage
		NO_x	Emissions Test Data
		Opacity	Type of Fuel Usage
		Operating Hours	Hours of Operation Data

Emission Unit Description	EU	Pollutant/ Parameter	Compliance Monitoring Record
Fire pump emergency engine	5	PM SO_2 NO_x Opacity Operating Hours	Type of Fuel Usage Type of Fuel Usage Emissions Test Data Type of Fuel Usage Hours of Operation Data
Scrubber emergency generator engine	6	NO_x SO_2 CO Opacity Operating Hours	Emissions Test Data Type of Fuel Usage Emissions Test Data Type of Fuel Usage Hours of Operation Data
Transfer house	M2	PM/Opacity	CAM Data
Northside distribution building	M3	PM/Opacity	CAM Data
Southside distribution building	M4	PM/Opacity	CAM Data
Lime storage silo	M5	PM/Opacity	CAM Data
Recycle fly ash silo	M6	PM/Opacity	CAM Data
Fly ash silo	M7	PM/Opacity	CAM Data
Lime unloading bin vent filter	M9	PM/Opacity	CAM Data

B. In addition to requirements outlined in Condition 6.A, recordkeeping for EU 1 (Unit 1 main stack) shall be in accordance with the following applicable requirements of Chapter 33-15-06, Chapter 33-15-12, Chapter 33-15-21 and Chapter 33-15-22 of the North Dakota Air Pollution Control Rules (NDAC) and the Acid Rain Program (40 CFR 72 and 40 CFR 75):

1) NDAC, §33-15-06-05, Reporting and Recordkeeping Requirements.

2) 40 CFR 60, Subpart A, §60.7, Notification and Recordkeeping.

3) NDAC, §33-15-21-09, Recordkeeping Requirements.

4) 40 CFR 63, Subpart UUUUU, §63.10032 and §63.10033, Notification, Reports and Records.

5) 40 CFR 75, Subpart F, Recordkeeping Requirements.

Applicable Requirements: NDAC 33-15-06, NDAC 33-15-12, NDAC 33-15-21, NDAC 33-15-22, 40 CFR 72, 40 CFR 75 and PTC10008 Rev. 1

C. Recordkeeping for EU 1, M2, M3, M4, M5, M6, M7 and M9 shall be in accordance with 40 CFR 64, §64.9 - Reporting and Recordkeeping Requirements paragraph (b) General Recordkeeping Requirements.

Applicable Requirement: NDAC 33-15-14-05.10 (40 CFR 64)

D. Recordkeeping for EU 2 shall be in accordance with 40 CFR 63, Subpart DDDDD, §63.7555 and §63.7560, Notification, Reports and Records.

Applicable Requirement: NDAC 33-15-22

E. The permittee shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sampling, measurement, report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings/computer printouts of continuous monitoring instrumentation, and copies of all reports required by the permit.

Applicable Requirement: NDAC 33-15-14-06.5.a(3)(b)[2]

7. **Reporting**:

A. Reporting for EU 1, M2, M3, M4, M5, M6, M7 and M9 shall be in accordance with NDAC 33-15-14-06.10 (40 CFR 64, §64.9) - Reporting and Recordkeeping Requirements, Paragraph (a) General Reporting Requirements.

Applicable Requirement: NDAC 33-15-14-06.10 (40 CFR 64)

B. For EU 1, reporting shall be in accordance with the following applicable requirements of Chapter 33-15-06, Chapter 33-15-12, Chapter 33-15-21 and Chapter 33-15-22 of the North Dakota Air Pollution Control Rules and the Acid Rain Program (40 CFR 72 and 40 CFR 75).

1) NDAC, §33-15-06-05, Reporting and Recordkeeping Requirements.

2) 40 CFR 60, Subpart A, §60.7, Notification and Recordkeeping. (Note: This condition also applies to EU M2, M3 and M4.)

3) NDAC, § 33-15-21-09, Reporting and Recordkeeping Requirements.

4) 40 CFR 63, Subpart UUUUU, §63.10030 and §63.10031, Notification, Reports and Records.

5) 40 CFR 75, Subpart F, Reporting Requirements.

6) Quarterly excess emissions reports for EU 1 shall be submitted by the 30th day following the end of each calendar quarter. Excess emissions are defined as emissions which exceed the emission limits for EU 1 as outlined in Condition 4. Excess emissions shall be reported for the following:

Parameter	Reporting Period
SO_2 lb/10^6 Btu	3-hour rolling average
SO_2 lb/hr	3-hour rolling average
NO_x lb/10^6 Btu	30-day rolling average
NO_x lb/hr	12-month rolling average
Opacity %	6-minute average

C. For EU 2, reporting shall be in accordance with 40 CFR 63, Subpart A, §63.10, Recordkeeping and Reporting and 40 CFR 63, Subpart DDDDD, Notification, Reports and Records.

D. The permittee shall submit a semi-annual monitoring report for all monitoring records required under Condition 6 on forms supplied or approved by the Department. All instances of deviations from the permit must be identified in the report. A monitoring report shall be submitted within 45 days after June 30 and December 31 of each year. If applicable, include semi-annual reporting required by NDAC 33-15-22-03, Subpart 5D in this report (§63.7550).

Applicable Requirements: NDAC 33-15-14-06.5.a(3)(c)[1] and [2]

E. The permittee shall submit an annual compliance certification report in accordance with NDAC 33-15-14-06.5.c(5) within 45 days after December 31 of each year on forms supplied or approved by the Department.

Applicable Requirement: NDAC 33-15-14-06.5.c(5)

F. For emission units where the method of compliance monitoring is demonstrated by an EPA Test Method or a portable analyzer test, the test report shall be submitted to the Department within 60 days after completion of the test.

Applicable Requirement: NDAC 33-15-14-06.5.a(6)(e)

G. The permittee shall submit an annual emission inventory report on forms supplied or approved by the Department. This report shall be submitted by March 15 of each year. Insignificant units/activities listed in this permit do not need to be included in the report.

Applicable Requirements: NDAC 33-15-14-06.5.a(7) and NDAC 33-15-23-04

8. **Facility Wide Operating Conditions**:

A. **Ambient Air Quality Standards**:

1) Particulate and gases. The permittee shall not emit air contaminants in such a manner or amount that would violate the standards of ambient air quality listed in Table 1 of NDAC 33-15-02, external to buildings, to which the general public has access.

2) Radioactive substances. The permittee shall not release into the ambient air any radioactive substances exceeding the concentrations specified in NDAC 33-10.

3) Other air contaminants. The permittee shall not emit any other air contaminants in concentrations that would be injurious to human health or well-being or unreasonably interfere with the enjoyment of property or that would injure plant or animal life.

4) Disclaimer. Nothing in any other part or section of this permit may in any manner be construed as authorizing or legalizing the emission of air contaminants in such manner that would violate the standards in Paragraphs 1), 2) and 3) of this condition.

Applicable Requirements: NDAC 33-15-02-04 and 40 CFR 50.1(e)

B. **Fugitive Emissions**: The release of fugitive emissions shall comply with the applicable requirements in NDAC 33-15-17.

Applicable Requirement: NDAC 33-15-17

C. **Open Burning**: The permittee may not cause, conduct, or permit open burning of refuse, trade waste, or other combustible material, except as provided for in Section 33-15-04-02 and may not conduct, cause, or permit the conduct of a salvage operation by open burning. Any permissible open burning under NDAC 33-15-04-02 must comply with the requirements of that section.

Applicable Requirement: NDAC 33-15-04

D. **Asbestos Renovation or Demolition**: Any asbestos renovation or demolition at the facility shall comply with emission standard for asbestos in NDAC 33-15-13.

Applicable Requirement: NDAC 33-15-13-02

E. **Rotating Pumps and Compressors**: All rotating pumps and compressors handling volatile organic compounds must be equipped and operated with properly maintained seals designed for their specific product service and operating conditions.

Applicable Requirement: NDAC 33-15-07-01.5

F. **Shutdowns/Malfunction/Continuous Emission Monitoring System Failure**:

1) Maintenance Shutdowns. In the case of shutdown of air pollution control equipment for necessary scheduled maintenance, the intent to shut down such equipment shall be reported to the Department at least 24 hours prior to the planned shutdown provided that the air contaminating source will be operated while the control equipment is not in service. Such prior notice shall include the following:

   a) Identification of the specific facility to be taken out of service as well as its location and permit number.

   b) The expected length of time that the air pollution control equipment will be out of service.

   c) The nature and estimated quantity of emissions of air pollutants likely to be emitted during the shutdown period.

   d) Measures, such as the use of off-shift labor and equipment, that will be taken to minimize the length of the shutdown period.

   e) The reasons that it would be impossible or impractical to shutdown the source operation during the maintenance period.

   f) Nothing in this subsection shall in any manner be construed as authorizing or legalizing the emission of air contaminants in excess of the rate allowed by this article or a permit issued pursuant to this article.

   Applicable Requirement: NDAC 33-15-01-13.1

2) Malfunctions.

   a) When a malfunction in any installation occurs that can be expected to last longer than 24 hours and cause the emission of air contaminants in violation of this article or other applicable rules and regulations, the person responsible for such installation shall notify the Department of such malfunction as soon as possible during normal working hours. The notification must contain a statement giving all pertinent facts, including the estimated duration of the breakdown. The Department shall be notified when the condition causing the malfunction has been corrected.

   b) Immediate notification to the Department is required for any malfunction that would threaten health or welfare or pose an imminent danger. During normal working hours the Department can be contacted at 701-328-5188. After hours the Department can be contacted through the 24-hour state radio emergency number 1-800-472-2121. If calling from out of state, the 24-hour number is 701-328-9921.

c) Unavoidable Malfunction. The owner or operator of a source who believes any excess emissions resulted from an unavoidable malfunction shall submit a written report to the Department which includes evidence that:

[1] The excess emissions were caused by a sudden, unavoidable breakdown of technology that was beyond the reasonable control of the owner or operator.

[2] The excess emissions could not have been avoided by better operation and maintenance, did not stem from an activity or event that could have been foreseen and avoided, or planned for.

[3] To the extent practicable, the source maintained and operated the air pollution control equipment and process equipment in a manner consistent with good practice for minimizing emissions, including minimizing any bypass emissions.

[4] Any necessary repairs were made as quickly as practicable, using off-shift labor and overtime as needed and possible.

[5] All practicable steps were taken to minimize the potential impact of the excess emissions on ambient air quality.

[6] The excess emissions are not part of a recurring pattern that may have been caused by inadequate operation or maintenance, or inadequate design of the malfunctioning equipment.

The report shall be submitted within 30 days of the end of the calendar quarter in which the malfunction occurred or within 30 days of a written request by the Department, whichever is sooner.

The burden of proof is on the owner or operator of the source to provide sufficient information to demonstrate that an unavoidable equipment malfunction occurred. The Department may elect not to pursue enforcement action after considering whether excess emissions resulted from an unavoidable equipment malfunction. The Department will evaluate, on a case-by-case basis, the information submitted by the owner or operator to determine whether to pursue enforcement action.

Applicable Requirement: NDAC 33-15-01-13.2

3) Continuous Emission Monitoring System Failures. When a failure of a continuous emission monitoring system occurs, an alternative method for measuring or estimating emissions must be undertaken as soon as possible. The owner or operator of a source that uses an alternative method shall have the burden of demonstrating that the method is accurate. Timely repair of the emission monitoring system must be made. The provisions of this subsection do not apply to sources that are subject to monitoring requirements in Chapter 33-15-21 (40 CFR 75, Acid Rain Program).

Applicable Requirement: NDAC 33-15-01-13.3

G. **Noncompliance Due to an Emergency**: The permittee may seek to establish that noncompliance with a technology-based emission limitation under this permit was due to an emergency. To do so, the permittee shall demonstrate the affirmative defense of emergency through properly signed, contemporaneous operating logs, or other relevant evidence that:

1) An emergency occurred, and that the permittee can identify the cause(s) of the emergency;

2) The permitted facility was at the time being properly operated;

3) During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards, or other requirements in this permit; and

4) The permittee submitted notice of the emergency to the Department within one working day of the time when emission limitations were exceeded longer than 24-hours due to the emergency. This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken. Those emergencies not reported within one working day, as well as those that were, will be included in the semi-annual report.

In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

Technology-based emission limits are those established on the basis of emission reductions achievable with various control measures or process changes (e.g., a New Source Performance Standard) rather than those established to attain a health-based air quality standard.

An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of this source, including acts of God, which requires immediate corrective action to restore normal operation, and that causes this source to exceed a technology-based emission limitation under this permit, due to unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

Applicable Requirement: NDAC 33-15-14-06.5.g

H. **Air Pollution from Internal Combustion Engines**: The permittee shall comply with all applicable requirements of NDAC 33-15-08-01 – Internal Combustion Engine Emissions Restricted.

Applicable Requirement: NDAC 33-15-08-01

I. **Prohibition of Air Pollution**:

1) The permittee shall not permit or cause air pollution, as defined in NDAC 33-15-01-04.

2) Nothing in any other part of this permit or any other regulation relating to air pollution shall in any manner be construed as authorizing or legalizing the creation or maintenance of air pollution.

Applicable Requirement: NDAC 33-15-01-15

J. **Performance Tests**:

1) The Department may reasonably require the permittee to make or have made tests, at a reasonable time or interval, to determine the emission of air contaminants from any source, for the purpose of determining whether the permittee is in violation of any standard or to satisfy other requirements of NDCC 23-25. All tests shall be made, and the results calculated in accordance with test procedures approved or specified by the Department including the North Dakota Department of Health Emission Testing Guideline. All tests shall be conducted by reputable, qualified personnel. The Department shall be given a copy of the test results in writing and signed by the person responsible for the tests.

2) The Department may conduct tests of emissions of air contaminants from any source. Upon request of the Department, the permittee shall provide necessary and adequate access into stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices, as may be necessary for proper determination of the emission of air contaminants.

Applicable Requirement: NDAC 33-15-01-12

3) Except for sources subject to 40 CFR 63, the permittee shall notify the Department by submitting a Proposed Test Plan, or its equivalent, at least 30 calendar days in advance of any tests of emissions of air contaminants required by the Department. The permittee shall notify the Department at least 60 calendar days in advance of any performance testing required under 40 CFR 63, unless otherwise specified by the subpart. If the permittee is unable to conduct the performance test on the scheduled date, the permittee shall notify the Department as soon as practicable when conditions warrant and shall coordinate a new test date with the Department.

Failure to give the proper notification may prevent the Department from observing the test. If the Department is unable to observe the test because of improper notification, the test results may be rejected.

Applicable Requirements: NDAC 33-15-14-06.5.a(3)(a), NDAC 33-15-12-02 Subpart A (40 CFR 60.8), NDAC 33-15-13-01.2 Subpart A (40 CFR 61.13), NDAC 33-15-22-03 Subpart A (40 CFR 63.7)

K. **Pesticide Use and Disposal**: Any use of a pesticide or disposal of surplus pesticides and empty pesticide containers shall comply with the requirements in NDAC 33-15-10.

Applicable Requirements: NDAC 33-15-10-01 and NDAC 33-15-10-02

L. **Air Pollution Emergency Episodes**: When an air pollution emergency episode is declared by the Department, the permittee shall comply with the requirements in NDAC 33-15-11.

Applicable Requirements: NDAC 33-15-11-01 through NDAC 33-15-11-04

M. **Stratospheric Ozone Protection**: The permittee shall comply with any applicable standards for recycling and emissions reduction pursuant to 40 CFR 82, Subpart F, except as provided for MVACs in Subpart B:

1) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to Section 82.156.

2) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to Section 82.158.

3) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to Section 82.161.

4) Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to Section 82.156.

Applicable Requirement: 40 CFR 82

N. **Chemical Accident Prevention**: The permittee shall comply with all applicable requirements of Chemical Accident Prevention pursuant to 40 CFR 68. The permittee shall comply with the requirements of this part no later than the latest of the following dates:

1) Three years after the date on which a regulated substance is first listed under this part; or

2) The date on which a regulated substance is first present above a threshold quantity in a process.

Applicable Requirement: 40 CFR 68

O. **Air Pollution Control Equipment**: The permittee shall maintain and operate air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. The manufacturer's recommended Operations and Maintenance (O&M) procedures, or a site-specific O&M procedure developed from the manufacturer's recommended O&M procedures, shall be followed to assure proper operation and maintenance of the equipment. The permittee shall have the O&M procedures available onsite and provide the Department with a copy when requested.

Applicable Requirement: NDAC 33-15-14-06.5.b(1)

P. **Prevention of Significant Deterioration of Air Quality** (40 CFR 52.21 as incorporated by NDAC Chapter 33-15-15): If this facility is classified as a major stationary source under the Prevention of Significant Deterioration of Air Quality (PSD) rules, a Permit to Construct must be obtained from the Department for any project which meets the definition of a "major modification" under 40 CFR 52.21(b)(2).

If this facility is classified as a major stationary source under the PSD rules and the permittee elects to use the method specified in 40 CFR 52.21(b)(41)(ii)(a) through (c) for calculating the projected actual emissions of a proposed project, then the permittee shall comply with all applicable requirements of 40 CFR 52.21(r)(6).

Applicable Requirement: NDAC 33-15-15-01.2

9. **General Conditions**:

A. **Annual Fee Payment**: The permittee shall pay an annual fee, for administering and monitoring compliance, which is determined by the actual annual emissions of regulated contaminants from the previous calendar year. The Department will send a notice, identifying the amount of the annual permit fee, to the permittee of each affected installation. The fee is due within 60 days following the date of such notice. Any source that qualifies as a "small business" may petition the Department to reduce or exempt any fee required under this section. Failure to pay the fee in a timely manner or submit a certification for exemption may cause this Department to initiate action to revoke the permit.

Applicable Requirements: NDAC 33-15-14-06.5.a(7) and NDAC 33-15-23-04

B. **Permit Renewal and Expiration**: This permit shall be effective from the date of its issuance for a fixed period of five years. The permittee's right to operate this source terminates with the expiration of this permit unless a timely and complete renewal application is submitted at least six months, but no more than 18 months, prior to the date of permit expiration. The Department shall approve or disapprove the renewal application within 60 days of receipt. Unless the Department requests additional information or otherwise notifies the applicant of incompleteness, the application shall be deemed complete. For timely and complete renewal applications for which the Department has failed to issue or deny the renewal permit before the expiration date of the previous permit, all terms and conditions of the permit, including any permit shield previously granted shall remain in effect until the renewal permit has been issued or denied. The application for renewal shall include the current permit number, description of any permit revisions and off-permit changes that occurred during the permit term, and any applicable requirements that were promulgated and not incorporated into the permit during the permit term.

Applicable Requirements: NDAC 33-15-14-06.4 and NDAC 33-15-14-06.6

C. **Transfer of Ownership or Operation**: This permit may not be transferred except by procedures allowed in Chapter 33-15-14 and is to be returned to the Department upon the destruction or change of ownership of the source unit(s), or upon expiration, suspension or revocation of this permit. A change in ownership or operational control of a source is treated as an administrative permit amendment if no other change in the permit is necessary and provided that a written agreement containing a specific date for transfer of permit responsibility, coverage, and liability between the current and new permittee has been submitted to the Department.

Applicable Requirement: NDAC 33-15-14-06.6.d

D. **Property Rights**: This permit does not convey any property rights of any sort, or any exclusive privilege.

Applicable Requirement: NDAC 33-15-14-06.5.a(6)(d)

E. **Submissions**:

1) Reports, test data, monitoring data, notifications, and requests for renewal shall be submitted to:

North Dakota Department of Health
Division of Air Quality
918 E Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

2) Any document submitted shall be certified as being true, accurate, and complete by a responsible official.

Applicable Requirement: NDAC 33-15-14-06.4.d

F. **Right of Entry**: Any duly authorized officer, employee or agent of the North Dakota Department of Health may enter and inspect any property, premise or place listed on this permit or where records are kept concerning this permit at any reasonable time for the purpose of ascertaining the state of compliance with this permit and the North Dakota Air Pollution Control Rules. The Department may conduct tests and take samples of air contaminants, fuel, processing material, and other materials which affect or may affect emissions of air contaminants from any source. The Department shall have the right to access and copy any records required by the Department's rules and to inspect monitoring equipment located on the premises.

Applicable Requirements: NDAC 33-15-14-06.5.c(2) and NDAC 33-15-01-06

G. **Compliance**: The permittee must comply with all conditions of this permit. Any noncompliance with a federally-enforceable permit condition constitutes a violation of the Federal Clean Air Act. Any noncompliance with any State enforceable condition of this permit constitutes a violation of NDCC Chapter 23-25 and NDAC 33-15. Violation of any condition of this permit is grounds for enforcement action, for permit termination, revocation and reissuance or modification, or for denial of a permit renewal application. Noncompliance may also be grounds for assessment of penalties under the NDCC 23-25. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

Applicable Requirements: NDAC 33-15-14-06.5.a(6)(a) and NDAC 33-15-14-06.5.a(6)(b)

H. **Duty to Provide Information**: The permittee shall furnish to the Department, within a reasonable time, any information that the Department may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. This includes instances where an alteration, repair, expansion, or change in method of operation of the source occurs. Upon request, the permittee shall also furnish to the Department copies of records that the permittee is required to keep by this permit, or for information claimed to be confidential, the permittee may furnish such recourse directly to the Department along with a claim of confidentiality. The permittee, upon becoming aware that any relevant facts were omitted, or incorrect information was submitted in the permit application, shall promptly submit such supplementary facts or corrected information. Items that warrant supplemental information submittal include, but are not limited to, changes in the ambient air boundary and changes in parameters associated with emission points (i.e., stack parameters). The permittee shall also provide additional information as necessary to address any requirements that become applicable to the source after the date a complete renewal application was submitted but prior to release of a draft permit.

Applicable Requirements: NDAC 33-15-14-06.5.a(6)(e), NDAC 33-15-14-06.6.b(3) and NDAC 33-15-14-06.4.b

I. **Reopening for Cause**: The Department will reopen and revise this permit as necessary to remedy deficiencies in the following circumstances:

1) Additional applicable requirements under the Federal Clean Air Act become applicable to the permittee with a remaining permit term of three or more years. Such a reopening shall be completed no later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the expiration date of this permit.

2) The Department or the United States Environmental Protection Agency determines that this permit contains a material mistake or inaccurate statements were made in establishing the emissions standards or other terms or conditions of this permit.

3) The Department or the United States Environmental Protection Agency determines that the permit must be revised or revoked to assure compliance with the applicable requirements.

4) Reopenings shall not be initiated before a notice of intent to reopen is provided to the permittee by the Department at least 30 days in advance of the date that this permit is to be reopened, except that the Department may provide a shorter time period in the case of an emergency. Proceedings to reopen and issue this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening shall be made as expeditiously as practicable.

Applicable Requirement: NDAC 33-15-14-06.6.f

J. **Permit Changes**: The permit may be modified, revoked, reopened, and reissued or terminated for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

Applicable Requirement: NDAC 33-15-14-06.5.a(6)(c)

K. **Off-Permit Changes**: A permit revision is not required for changes that are not addressed or prohibited by this permit, provided the following conditions are met:

1) No such change may violate any term or condition of this permit.

2) Each change must comply with all applicable requirements.

3) Changes under this provision may not include changes or activities subject to any requirement under Title IV or that are modifications under any provision of Title I of the Federal Clean Air Act.

4) A Permit to Construct under NDAC 33-15-14-02 has been issued, if required.

5) Before the permit change is made, the permittee must provide written notice to both the Department and Air Program (8P-AR), Office of Partnerships & Regulatory Assistance, US EPA Region 8, 1595 Wynkoop Street, Denver, CO 80202-1129, except for changes that qualify as insignificant activities in Section 33-15-14-06. This notice shall describe each change, the date of the change, any change in emissions, pollutants emitted, and any applicable requirement that would apply as a result.

6) The permittee shall record all changes that result in emissions of any regulated air pollutant subject to any applicable requirement not otherwise regulated under this permit, and the emissions resulting from those changes. The record shall reside at the permittee's facility.

Applicable Requirement: NDAC 33-15-14-06.6.b(3)

L. **Administrative Permit Amendments**: This permit may be revised through an administrative permit amendment, if the revision to this permit accomplishes one of the following:

1) Corrects typographical errors.

2) Identifies a change in the name, address or phone number of any person identified in this permit or provides a similar minor administrative change at the source.

3) Requires more frequent monitoring or reporting by the permittee.

4) Allows for a change in ownership or operational control of the source where the Department determines that no other change in the permit is necessary, provided that a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new permittee has been submitted to the Department.

5) Incorporates into the Title V permit the requirements from a Permit to Construct when the review was substantially equivalent to Title V requirements for permit issuance, renewal, reopenings, revisions and permit review by the United States Environmental Protection Agency and affected state review, that would be applicable to the change if it were subject to review as a permit modification and compliance requirements substantially equivalent to Title V requirements for permit content were contained in the Permit to Construct.

6) Incorporates any other type of change which the Administrator of the United States Environmental Protection Agency has approved as being an administrative permit amendment as part of the Department's approved Title V operating permit program.

Applicable Requirement: NDAC 33-15-14-06.6.d

M. **Minor Permit Modification**: This permit may be revised by a minor permit modification, if the proposed permit modification meets the following requirements:

1) Does not violate any applicable requirement.

2) Does not involve significant changes to existing monitoring, reporting, or recordkeeping requirements in this permit.

3) Does not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis.

4) Does not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include a federally enforceable emissions cap assumed to avoid classification as a modification under any provision of Title I of the Federal Clean Air Act; and alternative emissions limit approved pursuant to regulations promulgated under Section 112(i)(5) of the Federal Clean Air Act.

5) Is not a modification under NDAC 33-15-12, 33-15-13, and 33-15-15 or any provision of Title I of the Federal Clean Air Act.

6) Is not required to be processed as a significant modification.

Applicable Requirement: NDAC 33-15-14-06.6.e(1)

N. **Significant Modifications**:

1) Significant modification procedures shall be used for applications requesting permit modifications that do not qualify as minor permit modifications or as administrative amendments. Every significant change in existing monitoring permit terms or conditions and every relaxation of reporting or recordkeeping permit terms or conditions shall be considered significant. Nothing therein shall be construed to preclude the permittee from making changes consistent with this subsection that would render existing permit compliance terms and conditions irrelevant.

2) Significant permit modifications shall meet all Title V requirements, including those for applications, public participation, review by affected states, and review by the United States Environmental Protection Agency, as they apply to permit issuance and permit renewal. The Department shall complete review of significant permit modifications within nine months after receipt of a complete application.

Applicable Requirement: NDAC 33-15-14-06.6.e(3)

O. **Operational Flexibility**: The permittee is allowed to make a limited class of changes within the permitted facility that contravene the specific terms of this permit without applying for a permit revision, provided the changes do not exceed the emissions allowable under this permit, are not Title I modifications and a Permit to Construct is not required. This class of changes does not include changes that would violate applicable requirements; or changes to federally-enforceable permit terms or conditions that are monitoring, recordkeeping, reporting, or compliance certification requirements.

The permittee is required to send a notice to both the Department and Air Program (8P-AR), Office of Partnerships & Regulatory Assistance, US EPA Region 8, 1595 Wynkoop Street, Denver, CO 80202-1129, at least seven days in advance of any change made under this provision. The notice must describe the change, when it will occur and any change in emissions, and identify any permit terms or conditions made inapplicable as a result of the change. The permittee shall attach each notice to its copy of this permit. Any permit shield provided in this permit does not apply to changes made under this provision.

Applicable Requirement: NDAC 33-15-14-06.6.b(2)

P. **Relationship to Other Requirements**: Nothing in this permit shall alter or affect the following:

1) The provisions of Section 303 of the Federal Clean Air Act (emergency orders), including the authority of the administrator of the United States Environmental Protection Agency under that section.

2) The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance.

3) The ability of the United States Environmental Protection Agency to obtain information from a source pursuant to Section 114 of the Federal Clean Air Act.

4) Nothing in this permit shall relieve the permittee of the requirement to obtain a Permit to Construct.

Applicable Requirements: NDAC 33-15-14-06.3 and NDAC 33-15-14-06.5.f(3)(a), (b) and (d)

Q. **Severability Clause**: The provisions of this permit are severable, and if any provision of this permit, or the application of any provision of this permit to any circumstance, is held invalid, the application of such provision to other circumstances, and the remainder of this permit, shall not be affected thereby.

Applicable Requirement: NDAC 33-15-14-06.5.a(5)

R. **Circumvention**: The permittee shall not cause or permit the installation or use of any device of any means which conceals or dilutes an emission of air contaminants which would otherwise violate this permit.

Applicable Requirement: NDAC 33-15-01-08

10. **Phase II Acid Rain Provisions**:

Affected Source Unit: Coyote Station
ORIS Plant Code: 8222
Boiler ID: B1

This section incorporates the definition of terms in NDAC Chapter 33-15-21 by reference.

A. **Permit Requirements**:

1) The designated representative of each affected source and each affected unit at the source shall:

a) Submit a complete Acid Rain permit application (including a compliance plan) under 40 CFR 72 in accordance with the deadlines specified in NDAC 33-15-21-08.1 and 40 CFR 72.30, including application for permit renewal; and

b) Submit in a timely manner any supplemental information that the North Dakota Department of Health, Division of Air Quality, Air Pollution Control Program determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit.

2) The owners and operators of each affected source and each affected unit at the source shall:

a) Operate the unit in compliance with a complete Acid Rain permit application including any application for permit renewal or a superseding Acid Rain permit issued by the North Dakota Department of Health, Division of Air Quality, Air Pollution Control Program and

b) Have an Acid Rain permit.

Applicable Requirement: NDAC 33-15-21-08.1

B. **Monitoring Requirements**:

1) The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR 75 and 76.

2) The emissions measurements recorded and reported in accordance with 40 CFR 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and

emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

3) The requirements of 40 CFR 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Federal Clean Air Act and other provisions of the operating permit for the source.

Applicable Requirements: NDAC 33-15-21-08.1, NDAC 33-15-21-09, NDAC 33-15-21-10 and 40 CFR 74

C. **Sulfur Dioxide Requirements:**

1) The owners and operators of each source and each affected unit at the source shall:

   a) Hold allowances, as of the allowance transfer deadline, in the units compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and

   b) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.

2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Federal Clean Air Act.

3) An affected unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:

   a) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or

   b) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR 75, an affected unit under 40 CFR 72.6(a)(3).

4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

5) An allowance shall not be deducted in order to comply with the requirements under Condition 11.C.1)a) of this permit prior to the calendar year for which the allowance was allocated.

6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, this permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

Applicable Requirements: NDAC 33-15-21-08.1 and 40 CFR 73

D. **Nitrogen Oxide Requirements:**

NO_x Emission Limitation: The owner or operator shall not discharge, or allow to be discharged, from Boiler ID B1 emissions of NO_x to the atmosphere in excess of **0.86 lb/10^6 Btu** of heat input on an annual average basis. The owner/operator shall also comply with the duty under 40 CFR 76.9(d) to reapply for a NO_x compliance plan prior to expiration of this permit and requirements under 40 CFR 76.13 for calculating excess NO_x emissions.

Applicable Requirements: 40 CFR 76.6(a)(2), 40 CFR 76.9(d), 40 CFR 76.13, NDAC 33-15-21-08.1, 33-15-21-09 and 33-15-21-10

E. **Excess Emissions Requirements:**

1) The designated representative of an affected unit that has excess emissions of SO_2 in any calendar year shall submit a proposed offset plan, to the Administrator as required under 40 CFR 77, with a copy to the North Dakota Department of Health, Division of Air Quality, Air Pollution Control Program.

2) The owners and operators of an affected unit that has excess emissions of NO_x or SO_2 in any calendar year shall:

   a) Pay to the Administrator without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR 77; and

   b) Comply with the terms of an approved offset plan for SO_2, as required by 40 CFR 77.

Applicable Requirements: NDAC 33-15-21-08.1 and 40 CFR 77

F. **Recordkeeping and Reporting Requirements:**

1) Unless otherwise provided, the owners and operators of the source and each affected unit at the source shall keep on-site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the Administrator of the U.S. EPA or the North Dakota Department of Health, Division of Air Quality, Air Pollution Control Program:

   a) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on-site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

b) All emissions monitoring information, in accordance with 40 CFR 75, provided that to the extent that 40 CFR 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply.

c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

d) Copies of all documents used to complete an Acid Rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

2) The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 72, Subpart I and 40 CFR 75.

Applicable Requirements: NDAC 33-15-21-08.1 and NDAC 33-15-21-09

G. **Liability**:

1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain permit application, this Acid Rain Permit, or a written exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Federal Clean Air Act.

2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Federal Clean Air Act and 18 U.S.C. 1001.

3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

4) Each affected source and each affected unit shall meet the requirements of the Acid Rain Program.

5) Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated represented of an affected source) shall also apply to the owners and operators of such source and of the affected units at the source.

6) Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plan) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR 75 (including 40 CFR 75.16, 75.17 and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

7) Each violation of a provision of NDAC 33-15-21-08.1 through NDAC 33-15-21-10 and 40 CFR 72, 73, 74, 75, 76 and 77 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Federal Clean Air Act.

Applicable Requirements: NDAC 33-15-21-08.1, NDAC 33-15-21-09, NDAC 33-15-21-10 and 40 CFR 72, 73, 74, 75, 76 and 77

H. **Effect on Other Authorities**:

No provision of the Acid Rain Program, an Acid Rain permit application, this Acid Rain permit condition, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

1) Except as expressly provided in Title IV of the Federal Clean Air Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Federal Clean Air Act, including the provisions of Title I of the Federal Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

2) Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Federal Clean Air Act,

3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Applicable Requirements: NDAC 33-15-21-08.1 and 33-15-21-09

I. **Permit Shield**:

Each affected unit operating in accordance with this permit which is issued in compliance with Title IV of the Federal Clean Air Act, as provided in NDAC 33-15-21-08.1, NDAC 33-15-21-09 and 40 CFR 73, 77 and 78, and the regulations implementing Section 407 of the Federal Clean Air Act, shall be deemed operating in compliance with the Acid Rain Program, except as provided in 40 CFR 72.9(g)(6). The permit shield does not take effect until the effective date of the acid rain permit.

Applicable Requirements: NDAC 33-15-21-08.1, NDAC 33-15-21-09 and 40 CFR 73, 77 and 78

J. **Reopening for Cause**:

In addition to any reasons for reopening for cause previously stated in this permit, the Department will reopen and revise this permit as necessary to remedy deficiencies in the following circumstance: If additional requirements, including excess emissions requirements, become applicable to an affected source under Title IV of the Federal Clean Air Act or the regulations promulgated there under. Upon approval by the administrator of the United States Environmental Protection Agency, excess emissions offset plans shall be deemed to be incorporated into the permit.

Applicable Requirements: NDAC 33-15-14-06.6.f(1)(b)

11. **State Enforceable Only Conditions (not Federally enforceable):**

A. **General Odor Restriction**: The permittee shall not discharge into the ambient air any objectionable odorous air contaminant which exceeds the limits established in NDAC 33-15-16.

Applicable Requirement: NDAC 33-15-16

Attachment A

Compliance Assurance Monitoring (CAM) Plan for Particulate Matter Control

Coyote Station

Title V Permit to Operate No. T5-F84011

EU	EU Description	Air Pollution Control Equipment
1	Unit 1	Fabric Filter (Baghouse) (EP 1)
M2	Transfer House	Baghouse (EP M2)
M3	Northside Distribution Building	Baghouse (EP M3)
M4	Southside Distribution Building	Baghouse (EP M4)
M5	Lime Storage Silo	Baghouse (EP M5)
M6	Recycle Fly Ash Silo	Baghouse (EP M6)
M7	Fly Ash Silo	Baghouse (EP M7)
M9	Lime Unloading Bin Vent Filter	Baghouse (EP M9)

Table 1
Coyote Station
CAM Requirements

5/15/2013

Unit	Parameter	Control Device	Uncontrolled Potential to Emit >100 tons: Yes or No	Emission Limit	Exemption from CAM: Yes or No	CAM Required
Unit 1 Boiler	Visible Emissions	Fabric Filter	Yes	20%[1]	Yes -- COMS	No
	Particulate	Fabric Filter	Yes	0.1 lb/mmBtu[2]	No	Yes
	SO2	Spray Dryer	Yes	1.2 lb/mmBtu[2]	Yes -- CEMS	No
Transfer House	Visible Emissions	Baghouse	Yes	20%[3]	No	Yes
	Particulate	Baghouse	Yes	1.42 lb/hr	No	Yes
Northside Distribution Building	Visible Emissions	Baghouse	Yes	20%[3]	No	Yes
	Particulate	Baghouse	Yes	5.66 lb/hr	No	Yes
Southside Distribution Building	Visible Emissions	Baghouse	Yes	20%[3]	No	Yes
	Particulate	Baghouse	Yes	4.87 lb/hr	No	Yes
Lime Storage Silo	Visible Emissions	Baghouse	Yes	20%[4]	No	Yes
	Particulate	Baghouse	Yes	33.52 lb/hr	No	Yes
Recycle Fly Ash Silo	Visible Emissions	Baghouse	Yes	20%[4]	No	Yes
	Particulate	Baghouse	Yes	50.82 lb/hr	No	Yes
Fly Ash Silo	Visible Emissions	Baghouse	Yes	20%[4]	No	Yes
	Particulate	Baghouse	Yes	33.31 lb/hr	No	Yes
Lime Unloading Bin Vent Filter	Visible Emissions	Baghouse	Yes	20%[4]	No	Yes
	Particulate	Baghouse	Yes	5.7 lb/hr	No	Yes

[1]Except during startup, shutdown, or malfunction. Additionally, a maximum of 27% is permissible, but not for more than one six-minute period per hour.

[2]This standard does not apply during startup, shutdown, and malfunction.

[3]Except during startup, shutdown, or malfunction. Additionally, a maximum of 40% is permissible, but not for more than one six-minute period per hour.

[4]A maximum of 40% is permissible, but not for more than one six-minute period per hour.

Table 2
Coyote Station
Monitoring Approach
Control Device: Fabric Filter Baghouse for PM Control
EUI: Unit No. 1 Boiler

	Indicator No. 1	Indicator No. 2	Indicator No. 3
I. Indicator	Differential Pressure	Baghouse inlet zone temperature	Inspection/maintenance
A. Measurement Approach	Differential pressure across the baghouse is measured continuously using a DP gauge.	Temperature is measured continuously at the inlet of each baghouse zone using several temperature transmitters.	Bag performance is monitored by observing opacity and DP. Routine inspections are performed by qualified personnel.
II. Indicator Range	The indicator range is a pressure drop between 2.0 and 10.7 inches of water. Excursions trigger an inspection, corrective action, and a reporting requirement.	The indicator range is an inlet zone temperature of 160 - 390 °F during operation. Excursions trigger an inspection, corrective action, and a reporting requirement.	If inspections reveal repair work is needed, maintenance activities are initiated.
III. Performance Criteria			
A. Data Representativeness	The pressure gauge was installed at a representative location. An inlet and outlet gauge can be used to verify DP measurement.	Multiple temperature transmitters are installed at representative locations.	NA
B. Monitoring Frequency	Continuous during operation, alarm in control room during an excursion	Continuous during operation, alarm in control room during an excursion	Routine observations and maintenance
C. QA/QC Practices	Annual calibration of DP monitor	Regular comparison of temperature transmitters to identify anomalous readings	Qualified personnel perform inspections/maintenance
D. Data Collection Procedures	Plant Distributive Control System	Plant Distributive Control System	NA
E. Averaging Period	One minute data stored by DCS	One minute data stored by DCS	NA

5/15/2013

Table 3
Coyote Station
Monitoring Approach
Control Device(s): Fabric Filter Dust Collectors for PM/Visible Emissions Control
EUI: M2, M3, M4, M5, M6, M7, M9

	Indicator No. 1	Indicator No. 2	Indicator No. 3
I. Indicator	Differential Pressure	Visible Emissions	Inspection/maintenance
A. Measurement Approach	Differential pressure across the dust collectors is measured continuously using a DP gauge. An alarm will be initiated in the control room if the DP goes above the indicator range.	A routine visible emissions check is conducted weekly.	Routine inspection and maintenance activities are performed and documented by qualified personnel according to the plant preventative maintenance schedule. A routine DP reading is recorded weekly.
II. Indicator Range	*See Table 4. The dust collectors will be inspected whenever a DP alarm is initiated. If inspections reveal a problem or visible emissions, corrective action and a reporting requirement is required.	The indicator range is zero visible emissions. Excursions trigger an inspection, corrective action, and a reporting requirement.	Routine inspection and maintenance activities are performed according to a documented preventative maintenance schedule.
III. Performance Criteria			
A. Data Representativeness	The pressure gauges are installed at representative locations.	Visible emissions are checked from a representative location.	NA
B. Monitoring Frequency	Continuous	Visible emission checks documented by plant personnel	According to preventative maintenance schedule and weekly DP check
C. QA/QC Practices	Annual calibration of DP monitor	Only instructed personnel conduct visible emission checks.	Qualified personnel perform inspections/maintenance
D. Data Collection Procedures	Plant Distributive Control System records alarm status. Work orders kept on site.	Monthly checklists are kept on site.	Preventative maintenance records are maintained on site. DP checklist kept on site.
E. Averaging Period	None	NA	NA

Table 4
Coyote Station
Monitoring Approach
Dust Collector Indicator Ranges

5/15/2013

EUI	Emission Unit	Indicator Range
M2	Transfer House	≥ 1 to ≤ 13 inches water
M3	Northside Distribution Building	≥ 1 to ≤ 11 inches water
M4	Southside Distribution Building	≥ 1 to ≤ 11 inches water
M5	Lime Storage Silo	≥ 1 to ≤ 7 inches water
M6	Recycle Fly Ash Silo	≥ 1 to ≤ 10 inches water
M7	Fly Ash Silo	≥ 0.5 to ≤ 8 inches water
M9	Lime Unloading Bin Vent Filter	≥ 1 to ≤ 10 inches water

Statement of Basis for Title V Permit to Operate No. T5-F84011

Otter Tail Power Company
Coyote Station
Title V Permit to Operate T5-F84011
Renewal No. 4, Revision No. 0
Statement of Basis
(5/17/18)

Facility Background: The Coyote Station is a lignite-fired electrical power generating facility consisting of one unit: a Babcock and Wilcox cyclone-fired boiler with a maximum rated heat input of 5,800 x 10^6 Btu/hr. Pollution control equipment for the boiler is an Atomics International, Division of Rockwell International/Wheelabrator-Frye, Inc. Flue gas desulfurization (FGD) system. The FGD system consists of four parallel-connected spray dryer scrubbers in series with a fabric filter baghouse separated over fire air. Dry scrubbing is achieved with a lime and flyash slurry which combines with flue gas sulfur dioxide to precipitate calcium sulfate. The flue gas from the boiler is emitted through a circular stack 498 feet above grade. Other emission sources at the facility include an oil-fired auxiliary boiler rated at 202 x 10^6 Btu/hr, two diesel engine-driven emergency generators, a diesel engine-driven fire pump, coal and lime handling facilities, and two No. 2 fuel oil storage tanks.

A Permit to Construct (PTC) for the facility was issued effective August 9, 1977 (PTC 8/9/77). After a few amendments to the permit, construction was completed and operations began on March 29, 1981. On July 1, 1984, Permit to Operate (PTO) No. F84011 was issued to the station. The PTO was renewed on July 1, 1987 and then again on July 1, 1992. December 7, 1992, PTC 12/7/92 was issued to the facility for the installation of an emergency generator for the scrubber system. This construction was completed and incorporated into the PTO, which was again renewed on July 1, 1997. On December 18, 1997 Phase II Acid Rain Permit No. T4-F84011 was issued to the facility. Title V PTO No. T5-F84011 was first issued on July 15, 1998, and it was amended three times over the next four years. The Title V PTO was first renewed on September 17, 2003 and included the incorporation of the Phase II Acid Rain Permit and a CAM Plan as provisions in the Title V permit. On August 29, 2008, Renewal No. 2 of T5-F84011 was issued. PTC10008 was issued February 23, 2010 to establish conditions to satisfy the requirements of Regional Haze. Revision No. 1 to PTC10008 was issued March 14, 2011 to change the NO_x emission limit to a 30-day rolling average basis and establish a new compliance date of July 1, 2018.

On August 15, 2013, Title V PTO T5-F84011, Renewal No. 3 was issued for the Coyote Station concurrently with PTC13032. PTC13032 restricted auxiliary boiler operation to maintain status as a limited-use boiler as defined by 40 CFR 63, Subpart DDDDD. Revision No. 1 of T5-F84011 was issued September 13, 2013 for an administrative amendment to replace the attached initial PTC10008 with Revision No. 1 of Permit to Construct PTC10008. Revision No. 2 to Renewal No. 3 for T5-F84011 was issued October 2, 2013 for an administrative amendment to revise Table 2 in the CAM Plan, reflecting 390° F as the high temperature bypass setting for the Unit 1 baghouse. A letter dated November 6, 2013 to the Coyote Station granted Departmental approval for construction and operation of the activated carbon injecction mercury control at the facility. The activated carbon injecction mercury control included an insiginificant source unit/emission point, the carbon silo bin vent (EUM10/EPM10).

Current Action: On October 2, 2017, the Department received a timely application dated September 28, 2017 from Otter Tail Power Company requesting renewal of the Coyote Station Title V and Acid Rain Permit No. T5-F84011. Most of the changes in the draft renewal permit are administrative in nature except, the incorporation of the conditions of PTC10008, the addition of air pollution control on Unit 1 boiler (EU1) and clarification on requirements of applicable regulations.

The Department proposes to issue Renewal No. 4, Revision No. 0 of the Title V Permit to Operate T5-F84011 for a five-year term after the required 30-day public comment period and subsequent 45-day EPA review period. This statement of basis summarizes the relevant information considered during this renewal of the Title V permit. The legal basis for each permit condition is stated in the draft permit under the heading "Applicable Requirement."

Applicable Programs/As-Needed Topics:

1. **Title V.** The facility is considered a major source under NDAC 33-15-14-06 (40 CFR 70) due to potential emissions of PM_{10}, SO_2, NO_x, CO and VOC above 100 tons per year, and hazardous air pollutants (hydrogen chloride and hydrogen fluoride) above 10 tons per year.

2. **New Source Performance Standards (NSPS).** The following NDAC 33-15-12-03 and 40 CFR 60 subparts apply to the facility.

   Subpart A, General Provisions, applies to each source unit to which another NSPS subpart applies.

   Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators), applies to Unit 1 boiler (EU1) because it was constructed after August 17, 1971 (construction started in 1976), and it has a heat input rate greater than 250 million Btu per hour (actual 5,800 million Btu per hour). The Subpart D NO_x standard does not apply because construction was started before December 22, 1976.

   Subpart Y, Standards of Performance for Coal Preparation Plants applies to the facility's coal handling system (EU M2-M4). The system conveys and crushes more than 200 tons per day of coal and it was constructed after the Subpart Y effective date of October 24, 1974.

3. **National Emission Standards for Hazardous Air Pollutants (NESHAP).** No NDAC 33-15-13 and 40 CFR 61 subparts apply to the facility, with the possible exception of NDAC 33-15-13-02 (40 CFR 61, Subpart M, National Emission Standard for Asbestos), which may apply during facility modifications involving asbestos.

4. **Maximum Achievable Control Technology (MACT).** The following NDAC 33-15-22-03 and 40 CFR 63 subparts apply to the facility, which is a major source of Hazardous Air Pollutants (HAP).

Subpart A, General Provisions, applies to each source unit to which another MACT subpart applies.

Subpart ZZZZ, National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines applies to the engines (EU4, 5 and 6).

Subpart DDDDD, Industrial, Commercial and Institutional Boilers and Process Heaters applies to the auxiliary boiler (EU 2) because it is an oil-fired, industrial boiler located at a major source of hazardous air pollutants. The auxiliary boiler is considered a *limited-use* boiler under this subpart because the draft renewal permit and PTC13032 limit the combustion of fuel oil to an average annual capacity factor of 10 percent.

Subpart UUUUU, Coal- and Oil-fired Electric Utility Steam Generating Unit applies to the Unit 1 boiler (EU 1) because the unit is a coal- and oil-fired electric generating unit.

Subpart Q, National Emissions Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers) does not apply to this facility because it does not use chromium-based water treatment chemicals in an industrial process cooling tower.

5. **Acid Rain.** NDAC 33-15-21 and 40 CFR 72, 73, 75 and 76 apply to the facility since it is an existing electric utility steam generating plant rated at greater than 25 MWe.

6. **Prevention of Significant Deterioration (PSD).** The facility is a major source under NDAC 33-15-15 and 40 CFR 52.21 because it is a fossil-fuel fired steam electric plant with a heat input of more than 250 million Btu per hour that has the potential to emit more than 100 tons per year of a criteria pollutant. There are no changes contained in this permit renewal that increase potential emissions by a PSD-significant amount. Therefore, this permit renewal is not subject to PSD review.

7. **Best Available Control Technology (BACT).** Since there are no changes contained in this permit renewal that increase potential emissions by a PSD-significant amount, a BACT review is not required for this permit renewal.

8. **Gap Filling.** This permit contains gap filling for testing, monitoring or recordkeeping not otherwise required by rule. The gap filling conditions are generally identified by the applicable requirement: NDAC 33-15-14-06.5.a(3)(a).

9. **Streamlining Decisions.** Not applicable because no streamlining was involved with this renewal.

10. **Compliance Assurance Monitoring (CAM).** CAM applies to the dry scrubber and baghouse for Unit 1 (EU 1) and the baghouses for the coal and lime handling facilities (EU M2-M9)

11. **Permit Shield.** This permit contains a permit shield.

12. **New Conditions/Limits.** This permit renewal incorporates clarification on the limits, associated monitoring, recordkeeping and reporting for 40 CFR 63, Subpart ZZZZ, Subpart UUUUU and PTC10008 Rev. 1.

13. **40 CFR 98 - Mandatory Greenhouse Gas Reporting.** This rule requires sources above certain emission thresholds to calculate, monitor and report greenhouse gas emissions. According to the definition of "applicable requirement" in 40 CFR 70.2, neither Subpart 98 nor Clean Air Act Section 307(d)(1)(V), the CAA authority under which Subpart 98 was promulgated, are listed as applicable requirements for the purpose of Title V permitting. Although the rule is not an applicable requirement under 40 CFR 70, the source is not relieved from the requirement to comply with the rule separately from compliance with their Part 70 operating permit. It is the responsibility of each source to determine applicability to the subpart and to comply, if necessary.

Permit Changes by Condition In this Draft Renewal:

Note: Clerical changes were made to some sections to update to current North Dakota (ND) format and correct errors; these changes may not be specifically addressed below.

Cover: Format, source location, source type and dates were updated.

Table of Contents: Page numbers and condition headings were updated as needed. PTC10008, Attachment B was removed.

1. **Emission Unit(s) Identification**: In the table, separated over fire air and activated carbon injection was added as air pollution control for Unit 1 boiler (EU1/EP1). The insignificant unit, carbon silo bin vent filter, was added. The emergency generator footnote was updated with the applicable regulation, 40 CFR 63, Subpart ZZZZ. CEMS information from the previous Condition No. 2 (Continuous Emission Monitoring System (CEMS) Identification) was moved here to Condition No. 1.C. All the following condition numbers were updated accordingly. Coal conveying/handling equipment was added to the fugitive emissions sources.

2. **Fuel Restrictions**: This section was previously "Special Conditions." The State enforceable only condition of burning used oil in the Unit 1 boiler (EU1) was moved from the previous Condition No. 12.B to Condition No. 2.A.1.

3. **Applicable Standards and Miscellaneous Conditions**: Previously "Standards", all applicable standards were updated to the current ND format.

4. **Emission Unit Limits**: Applicable standard limitations were included in the table for Unit 1 boiler (EU1) and the emergency engines (EU4, EU5, EU6). The NO_x limit for EU 1 was added from PTC10008 Rev. 1. Opacity limits were moved from Condition No. 6 to here in Condition No. 4.B.

5. **Monitoring Requirements and Conditions**: Applicable standard monitoring (Hg and HCl for 33-15-22-03, Subpart 5U) was included in the table for Unit 1 boiler (EU1). The condition number and applicable requirement references in the table were updated for several emission units. Monitoring from PTC10008 Rev. 1 for EU1 was added to the table and monitoring was added for the applicable standards. Condition No. 5.B.2 for COMS monitoring was updated and Condition No. 5.B.11 was added.

6. **Recordkeeping Requirements**: Applicable standard recordkeeping (Hg and HCl for 33-15-22-03, Subpart 5U) was included in the table for Unit 1 boiler (EU1). Recordkeeping from PTC10008 Rev.1 and applicable standards was added.

7. **Reporting**: Reporting from PTC10008 Rev.1 and applicable standards was added.

8. **Facility Wide Operating Conditions**: Conditions 8.A, E, G and J were revised to reflect the current ND facility wide operating conditions.

9. **General Conditions**: Conditions 9. H, I and M were revised to reflect the current ND general conditions.

10. **Phase II Acid Rain Provisions**: Conditions were revised to reflect the current ND Acid Rain Program conditions.

11. **State Enforceable Only Conditions (not Federally enforceable)**: The State enforceable only condition of burning used oil in the Unit 1 boiler (EU1) was moved from here to Condition No. 2.A.1.

Attachment A – Compliance Assurance Monitoring (CAM) Plan: Table 2 annual calibration of the temperature transmitters for the baghouse was replaced with regular comparison of temperature transmitters for anomalous readings.

Attachment B – PTC 10008 (Regional Haze) was removed and incorporated into the Title V PTO.

<u>Comments/Recommendations</u>: It is recommended that Renewal No. 4, Revision No. 0 of Title V Permit to Operate No. T5-F84011 be processed and considered for issuance following a 30-day public comment period and a subsequent 45-day EPA review period.